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Flue Gas Desulfurization In Power Plants

Status Report

U.S. ENVIRONMENTAL PROTECTION AGENCY
Division of Stationary Source Enforcement
Office of Enforcement
Washington, D.C. 20460
April 1977

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This report summarizes the current state of the art of major SO_2 scrubbers for power plants. Technological problems and solutions are described. Available installation and operating costs are summarized. Histories of operational systems are presented.

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FLUE GAS DESULFURIZATION

IN

POWER PLANTS

Status Report

Division of Stationary Source Enforcement
Office of Enforcement

April, 1977

by

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CONTENTS

I SUMMARY AND CONCLUSIONS

II INTRODUCTION
- A. Background 5
- B. Related Reports 6
- C. Compliance Status 8
- D. FGD Installation Status 10
- E. Japanese Experience 10

III THERMOCHEMICAL PROCESSES
- A. Lime and Limestone Systems 13
- B. Wellman-Lord Systems 22
- C. Double Alkali Systems 24
- D. Chiyoda Systems 27
- E. Magnesium Oxide Systems 29

IV COSTS 32

APPENDIX A: OPERATIONAL SYSTEMS
APPENDIX B: FGD INSTALLATION LISTS
APPENDIX C: FGD SYSTEM COSTS
REFERENCES

I SUMMARY AND CONCLUSIONS

Sulfur oxides and their derivatives present serious threats to human health. To limit atmospheric concentrations of sulfur dioxide to safe levels, EPA promulgated primary (health related) and secondary (welfare related) standards in 1971. Recent information indicates that acid sulfates, which are the oxidation products of sulfur dioxide, may cause more serious health problems than sulfur dioxide itself.

The approximately 970 power plants that burn oil and coal to produce electricity are the major sources of sulfur dioxide emissions in this country. EPA has consistently maintained that reducing the sulfur dioxide emissions, rather than relying on atmospheric dilution, is the most appropriate way to achieve the ambient standards.

Sulfur dioxide emissions can be reduced at power plants by burning fuels with a lower sulfur content. To take advantage of the large supplies of high sulfur Eastern and Midwestern coals, however, sulfur removal processes are needed. At many plants the coal is washed to extract sulfur, but only the inorganic sulfur is removed. Several other processes are being developed including solvent refined coal, coal gasification, and fluid bed combustion. These processes improve sulfur removal but will not be available on a wide scale until the 1980's. The only process with high sulfur removal efficiency that is widely available now is flue gas desulfurization (FGD).

In the last five years or so, FGD systems have been improved and developed substantially. In 1973 when EPA held national public hearings to determine the compliance status of United States power plants, there were 10 operational FGD systems and 34 more under construction or operational. At the time of this report, which updates the public hearings, 30 systems are operational and 86 are under construction or planned. In Japan, 133 systems have been installed. FGD systems are now offered for sale by at least 13 reputable United States firms. In

addition to the original lime and limestone systems, many second generation processes are in various stages of development. Some of the new processes are regenerable systems that produce no significant waste material.

FGD systems have demonstrated effective control of sulfur dioxide. Most present systems are designed to remove 80 percent or more sulfur dioxide. Operation has demonstrated that these efficiencies are attainable.

Numerous equipment problems have occurred in FGD systems. However, much progress has been made in eliminating or controlling these problems. Experience shows that with reasonable maintenance programs, the systems can be kept available 80 percent or more of the time. System reliability can be expected to increase further as the result of continuing research and development.

FGD systems are expensive to install and operate. It can be expected that these costs will be passed on to consumers of electric power. If all power plants installed FGD systems, the rate increase for electric power would be about 7.7 percent for the average residential consumer. But not all plants will need FGD systems so the expected rate increase is much less than 7.7 percent. EPA believes these costs are reasonable.

This report summarizes the status of power plant flue gas desulfurization (FGD) systems. Most FGD activity has occurred in the United States and Japan. In both countries, many different system types are being developed and operated.

The early United States systems used limestone injected into the boiler followed by tail gas scrubbing. More effective designs have evolved but most installations in this country still use either lime or limestone. The predominance of lime and limestone systems is expected to continue well into the 1980's. Second generation systems, however, are becoming competitive. These include Wellman-Lord, double alkali, Chiyoda, and magnesium oxide.

The technical status and available cost information for some leading FGD systems are summarized in this report. The operational power plant systems in the United States are reviewed in Appendix A. Some conclusions are listed below.

A. Lime and Limestone Systems

Many equipment problems have been experienced with lime and limestone systems. But much progress has also occurred, and the problems are now sufficiently understood that systems can be designed and operated with good reliability. The systems can not be expected to operate trouble-free; a reasonable amount of maintenance, however, should keep the system operational most of the time. Routine maintenance can be facilitated by installing several parallel FGD modules. Individual modules can be taken off line and serviced during periods of low power demand. Additionally, spare modules can be installed and rotated in service, with maintenance being done to the modules as they come off line.

Records of operating systems show that lime and limestone systems can operate consistently with reliabilities of 80 percent or higher. System reliability should steadily grow as technology improves with increased operating experience.

Lime and limestone systems are effective in controlling SO_2 emissions. Operating efficiencies of 80 percent and higher are achieved in normal operation.

Several full scale systems installed on coal-fired plants have demonstrated satisfactory operation. These include Louisville Gas and Electric's Paddy's Run Station (lime scrubbing), Kansas City Power and Light's La Cygne Station (limestone scrubbing) and Arizona Public Service's Cholla Station (limestone scrubbing).

Lime and limestone systems produce large quantities of sludge as an end product. To prevent land and water pollution, the sludge should be properly managed. Several commercial methods are now available to solidify the sludge. The solid sludge can be landfilled without significant adverse effect on the environment. Other disposal methods are being evaluated and may be satisfactory in some situations. These include converting the sludge to gypsum, or compacting dewatered sludge between layers of flyash with an underlaid drainage system.

B. Wellman-Lord Systems

The Wellman-Lord system is capable of high SO_2 removal efficiency and produces a salable end product such as elemental sulfur. The system has been demonstrated on oil-fired power plants and other applications. It is expected to be demonstrated soon on a 115 MW coal-fired power plant. The major disadvantage of the system is a relatively high capital cost.

C. Double Alkali

The double alkali system is capable of higher SO_2 removal efficiency than lime or limestone systems because it uses a more reactive absorbing medium. The system offers better reliability than lime or limestone systems because the double alkali scrubbing liquor has less tendency to form scale. Double alkali systems have been demonstrated on small scale applications and now appear ready for large scale applications.

D. Chiyoda System

The Chiyoda system is capable of high SO_2 removal efficiency and has been demonstrated on many oil-fired power plants in Japan. The system has also been demonstrated on a 20 MW coal-fired plant in the United States. The system appears ready for large scale applications.

E. Magnesium Oxide Systems

Magnesium-oxide systems have operated for short periods on full scale oil-fired and coal-fired plants. The operating experience indicates that the process is technically feasible. The experience underscores the need to provide reliable regeneration facilities, either by locating them at the power plant site or by contracting with a well established outside firm. Magnesium oxide systems are the least expensive of the regenerable systems, and can be less expensive than limestone systems if sludge fixation is required.

II INTRODUCTION

A. Background

Power plants that burn coal and oil to produce electricity are the major source of sulfur oxides (SO_x) in the United States. Because of this, the United States Environmental Protection Agency (EPA) is committed to controlling power plant emissions. Under Section 111 of the Clean Air Act, EPA promulgated new source performance standards (NSPS) that apply to all power plants constructed or modified after August 17, 1971; the NSPS limit allowable emissions from oil-fired plants and coal-fired plants respectively to 0.8 and 1.2 pounds of SO_2 per million BTU of heat input (40 CFR 60.43). Plants constructed or modified before August 17, 1971 are subject to regulations adopted by the States as part of the EPA approved State Implementation Plans (SIP's). The allowable SO_2 emissions under the SIP's vary from State to State.

As part of its program to implement emissions standards for power plants, EPA held national public hearings in October and November 1973 to review compliance with SO_2 emission limitations and considered all relevant issues. Testimony was heard from representatives of electric utilities, trade associations, vendors of pollution control equipment, and other interested parties. The EPA hearing panel made findings that included the following:

a) Flue gas desulfurization (FGD) systems must be installed on a large number of power plants if SO_2 emission requirements adopted pursuant to the Clean Air Act are to be met in the 1970's.

b) Established SO_2 emission limitations would not be met by SIP compliance dates unless the electric utility industry made prompt commitments to install FGD systems.

c) Reliability and efficiency of FGD systems have been sufficiently demonstrated on full scale units to warrant widespread commitments to FGD systems for control of SO_2 emissions from coal and oil-fired power plants.

d) Incentives should be created for the installation of FGD systems by vigorously enforcing reasonable schedules for complying with SO_2 emission limitations.

EPA has closely followed the progress of FGD technology during the two-year period since the national public hearings. Two symposiums on FGD technology have been held, and a bimonthly Summary Report is issued on the status of FGD systems that are operational, under construction, or being planned. In September 1974, EPA issued a report called "Flue Gas Desulfurization: Installations and Operations", which reviewed the advances of FGD technology since the 1973 public hearings. This report updates progress since the 1974 report.

B. Related Reports

In a Position Paper on Regulation of Atmospheric Sulfates issued in September 1975, EPA reaffirmed the need to limit SO_2 emissions from power plants as a means of reducing health hazards apparently associated with atmospheric sulfates.[9]

The EPA report suggests that SO_2 emissions be limited through the following measures:

a) continued emphasis on compliance with SO_2 emission standards by existing sources;
b) emphasis on attainment of emission standards by new facilities using available technology;
c) continued encouragement for use of low-sulfur fuels or installation of FGD where needed to meet emission standards.

The National Academy of Sciences has recently issued two reports which affirm the need for FGD to control SO_2 emissions. In March 1975, the Commission on Natural Resources issued a report entitled "Air Quality and Stationary Source Emission Control" in which a major finding was that emissions of sulfur oxides (and respirable particulate matter) must be limited in order to protect public health. Discussing four near-term approaches for minimizing the impact of SO_2 emissions, the Report expresses considerable optimism for FGD technology, stating that there have been rapid advances in the understanding and application of scrubbing technology in the past year.

A second report, issued in March 1975 by the Committee on Mineral Resources and the Environment entitled "Mineral Resources and the Environment", cites FGD as "technology now available which, if applied efficiently, could help to achieve clean air standards." The report also recommends that the Federal Government not approve the tall stack intermittent control systems for dispersing emissions of sulfur oxides as a permanent solution, but require instead the installation of pollution abatement equipment in both new and existing coal-fired plants.

The Department of Commerce conducted a study to determine how soon, at what cost, and with what trade-offs, commercially available SO_x emission controls can be installed in all coal-fired plants in the Northeastern United States. Their report was issued September 10, 1975. Among other findings, the study panel found that several continuous SO_x technologies are commercially available, including lime and limestone systems, and coal beneficiation (which involves washing the coal to remove inorganic sulfur compounds). The panel suggested that their most significant finding was that if lime or limestone systems must be used, coal beneficiation combined with FGD will generally be the most economical and most all-around choice.

C. Compliance Status

EPA keeps records of power plants showing whether they are in or out of compliance with SIP and NSPS emission regulations. A summary of the current compliance status is shown in Table 1. This table accounts for most plants burning coal or oil, except for small plants of less than 25 MW capacity. The plants that burn combinations of coal and oil are counted twice. The plants that burn only natural gas are all in compliance with SO_2 regulations. All plants in Indiana, Illinois, and Ohio are excluded from Table 1 because these States had no applicable SO_2 regulations when the last count was made (EPA promulgated regulations for Ohio on August 27, 1976).

EPA's objective is to have all power plants in compliance. This is being accomplished by enforcement activity on the federal, State, and local levels. EPA's enforcement authority is granted by the Clean Air Act (42 U.S.C. 1857) in Section 113. Under this section, EPA can issue administrative orders to sources out of compliance or can bring civil or criminal actions in Federal District Courts. Administrative orders

Table 1. Status of Power Compliance with SIP and NSPS SO_2 Regulations in the United States (August 1976).

	Number of Plants	
	Total[a]	Out of Compliance[b]
Coal-Fired	406	59
Oil-Fired	202	9

Notes:

a) Plants greater than 25 MW except those in Ohio, Indiana and Illinois, which had no applicable SO_2 regulations when the count was made.

b) A plant is out of compliance if it does not meet SIP or NSPS standards.

have been issued to or are being prepared for many of the plants now out of compliance. Orders to some plants are being delayed because of legal challenges to the regulations.

D. FGD Installation Status

FGD systems are classified as operational, under construction, or being planned. EPA keeps track of FGD systems in each category and publishes the results in a bimonthly Summary Report. The current totals are given in Table 2. As shown, the numbers in each category have increased significantly since 1973.

Currently there are 116 FGD systems in the three categories. A list of these units is provided in Table B-1. The 27 operational units are briefly reviewed in Appendix A.

Table 2. FGD systems installed on United States Power Plants.

	Nov. 1973	Sept. 1974	August 1976
Operational	10	19	30
Under Construction	16	14	21
Planned	18	60	65
	44	93	116

E. Japanese Experience

No discussion of FGD experience would be complete without mention of Japanese technology. Japan has compiled an impressive record of installations and operation. The installations are characterized by a great variety of processes and applications. Most are installed on industrial and utility boilers. S/ince land for sludge disposal is limited, the Japanese installations include several processes that produce recoverable byproducts instead of throwaway sludge. Even the lime and limestone systems are designed to produce a gypsum product that is used to make wallboard.

Japanese FGD technology was reviewed at the March 1976 EPA symposium (1). The report summarized the major FGD systems that will be operational by the end of 1976; this information is reproduced in Table 3. As shown, there will be 333 units controlling the equivalent of 24,000 MW. Most of the units are installed on oil-fired sources, which are easier to control than coal-fired sources. The report summarizes Japanese installations as follows:

> "About 100 FGD plants including several large ones with a capacity of 150-500 MW went into operation in 1975. Operation of most plants has been trouble-free. The large plants have attained more than 97% availability. The total FGD (gas flow) capacity which was about 30 million Nm^3/hr (10,000 MW equivalent) at the end of 1974 will exceed 70 million Nm^3/hr by the end of 1976. The rapid growth is due to the economical advantage of FGD over the use of low-sulfur fuels and to the reliability of plant operation."

The report also explains that the number of new installations will diminish because of the recent economic depression, overproduction of FGD byproducts, the desire to await development of combined NO_x and SO_x control systems, and the near attainment of the ambient SO_2 standard. The last reason cited is a good indication of the effectiveness of FGD systems. According to Ando, the average annual SO_2 concentration in big cities was 0.05 part per million (ppm) a few years ago but is now down to 0.02 - 0.03 ppm.

As shown in Table 3, Japanese FGD systems will be scrubbing the equivalent of 24,000 MW by the end of 1976. This is about four times the current installed United States FGD capacity.

Table 3. Major Japanese FGD Processes and Plant Capacities (Operational at the end of 1976).[a]

Process	Number of Plants	Total Capacity[b] MW
Mitsubishi (MHI)	31	5969
Chiyoda	15	1829
Babcock-Hitachi	9	1780
Wellman-MKK	10	1373
Fuji Kasui-Sumitomo	7	1318
Ohji	49	1280
Kureha-Kawasaki	3	980
IHI-TCA	26	929
Mitsui-Chemico	5	913
Tsukishima-Balco	20	885
Kurabo	70	860
Showa Denko-Ebara	16	819
Chemico-IHI	2	600
Kureha	8	477
Wellman-OKK	6	433
Nippon Steel	2	390
Kobe Steel	4	357
Nippon Kokan	1	253
Tsukishima	4	228
MKK	17	131
IHI-TCA	3	317
Hitachi Ltd.	3	197
Kurabo	5	196
Kawasaki	3	194
Chemico-Mitsui	1	167
Ebara	4	143
Chemico-Mitsui	1	126
Showa Denko	2	123
Chuoh-MKK	2	104
Nippon Kokan	2	76
"	1	60
Sumitomo H.I.	1	50
Shell	1	40
Onahama-Tsukishima	1	29
Mitsui Mining	1	27
TOTAL	333	23,655

(a) Reproduced in part from Ando (1).
(b) Converted on the basis that 3000 Nm^3/hr is equivalent to 1 MW.

III TECHNOLOGICAL PROGRESS

Operating experience in the United States and Japan demonstrates that lime, limestone, magnesium oxide, Wellman-Lord, and Chiyoda flue gas desulfurization systems are technically feasible. These systems are discussed below. Many additional systems (not discussed) are in various stages of development or operation.

A. Lime and Limestone Systems

Limestone FGD systems were formerly designed as boiler injection systems with tail gas scrubbing. The intent was to use the high temperatures in the boiler to convert limestone to more reactive lime, which would then remove SO_2 from the flue gas. Significant operating problems resulted because of plugging and erosion of boiler internals and because of inefficient limestone utilization. EPA began a carefully designed research and development program to improve FGD system design (2,3,4). As a result of this program and similar efforts by equipment manufacturers and utilities, the state of the art has advanced significantly.

Currently about 30 lime and limestone systems are operational in the United States. Results have been mixed with certain installations operating better than others. Some of the systems have performed successfully, demonstrating good SO_2 removal efficiencies and equipment reliability.

SO_2 removal efficiency is determined by many variables, including the reactivity of the scrubbing liquid, the degree of gas-liquid contact, the ratio of gas flow rate to liquid flow rate, gas residence time, and the number of scrubber stages. The last three variables have been studied at a 170 MW horizontal absorber using a lime slurry at Southern California Edison's Mohave plant (5). It was found that nearly any desired SO_2 removal efficiency could be obtained, and that 90 percent removal efficiency could be obtained with a liquid to gas ratio of 17.5 gallons per 1000 ACF

using all four stages of the scrubber. In addition, a 30 day test run has been made at the Louisville Gas and Electric Paddy's Run lime scrubber (6). SO_2 removal efficiencies were found to range between 80 and 90 percent. Twenty-two tests have been run at the Will County Station. The measured efficiency ranged from 66 to 94 percent, averaging 84 percent (7). The Ia Cygne system was tested in 1975. In one test series, six modules were tested and in a second test all seven modules were tested. The average SO_2 removal efficiencies were 76.1 and 80 percent respectively (8). These performance data demonstrate that high removal efficiencies are attainable. There seems to be general agreement on this. In fact, the design efficiencies of most operating lime and limestone systems are 80 percent or higher (9).

The major operating problems experienced with scrubbers have been scaling, plugging, corrosion, and erosion of equipment parts. In many but not all instances the problems have been severe, resulting in frequent shutdowns and very short life for reheaters, fans, slurry recycle pumps, and piping. The causes of these problems, however, are now sufficiently understood that systems can be designed and operated with satisfactory reliability. Maintenance work on the systems will still be required, but modules can be expected to operate 80 percent or more of the time needed.

Many FGD systems are now being designed with extra modules. If four parallel modules are needed, for example, five will be installed. Bypasses are also installed around each unit, and the modules can be rotated in service with one module down at all times for any needed maintenance. This arrangement will significantly improve the reliability of the overall system.

Scaling has been a major problem at some plants. If scrubber chemistry is uncontrolled, hard sulfite and sulfate scale deposits can block the small orifices of nozzles or sieve trays; chunks that break off equipment walls can damage pumps or plug strainers. The chemistry of scale formation is becoming increasingly better understood. As a result, methods have been developed to inhibit scale by

controlling the process chemistry. In the Combustion Engineering design emphasis is placed on controlling the pH (acidity) of the scrubbing liquor by properly selecting the lime or limestone addition rates and addition points (6). In the scrubber the calcium sulfite scaling can be minimized by keeping the scrubber pH below 7 or 8. In the reaction tank (through which the scrubber slurry is recycled) the pH is raised by addition of lime or limestone makeup and the bisulfites are converted to insoluble sulfites, which precipitate and are removed. Sulfates present in the scrubbing water are also removed in the reaction tank by co-precipitation with sulfites. An additional process control to prevent sulfate scaling in the scrubber is to maintain sulfate crystals in the scrubbing slurry. As new sulfates are formed they tend to precipitate on the recirculated crystals rather than on the equipment.

The above process controls have been implemented very successfully at Louisville Gas and Electric's Paddy's Run Station. Significant scaling has never been observed while operating with lime slurries. (Scaling did occur during a short test run with limestone.) The Paddy's Run experience is very encouraging and tends to show that scaling can be prevent. (at least in lime systems) by proper control of process chemistry. Even if scaling can not be eliminated, the FGD systems can be kept operational by regular maintenance programs.

Plugging is a problem similar to scaling, but consists of soft deposits resulting from mechanical settling rather than hard scale from chemical reaction and deposition. The soft deposits form in the demister section and in extreme cases can severely restrict the flow of gas. Plugging has been counteracted by installing sprays around the demister to periodically knock the material loose with jets of water. In order to operate with a closed water loop, however, the amount of water available for cleaning is limited. As a result, most units are shut down periodically and cleaned out manually.

Many FGD installations are designed with several modules in parallel. Sometimes an extra module is provided. This allows the

modules to be rotated in service so that regular maintenance can be provided without reducing boiler load. The spare equipment approach is common in industry as the following examples will illustrate.

The most common examples of spare equipment are extra pumps and compressors installed at critical points. Major process units are also sometimes spared. Examples include catalytic reformers in petroleum refineries that have one module always off-line for catalyst regeneration. Delayed cokers in refineries also have one module off-line to remove the coke product. Claus plants sometimes have a spare reactor in case of malfunction. Coke oven batteries have spare charging cars, quench cars, and oven doors. Control equipment is also sometimes spared; examples include bag houses that are compartmentalized so that one compartment can be cleaned while the other compartments operate.

The need for scrubber maintenance and spare modules may decrease as more is learned about process control. Recent results obtained at EPA's Shawnee test facility show that demister plugging can be reduced substantially by process modifications. This is done by using diluted clarifier liquor for demister washing or by operating with at least 85 percent alkali utilization. These approaches can be used with both lime and limestone systems. Results obtained at Shawnee are summarized in an EPA report (4) and discussed below.

Most plants wash demisters with fresh water to inhibit scale formations. The amount of water that can be used is limited, if the system is to operate closed loop. EPA's Shawnee results indicate that water from the top of the clarifier can be used if it is diluted with fresh water. The clarifier water is normally recycled to the scrubbers so it can be used generously without opening the water loop. Fresh dilution water desaturates the clarifier water and inhibits scale formation. The Shawnee test results indicate that continuous underwash with diluted clarifier liquor and intermittent topwash with fresh water will prevent serious plugging in demisters. In the tests, solids built up until about 10 percent of the gas passages were blocked; no further buildup occurred. The tests were run on a closed loop limestone system.

The total amount of wash water needed was 0.4 gallons per minute per square foot of duct cross sectional area.

EPA Shawnee results have also shown that plugging can be nearly eliminated by operating the FGD system with an alkali utilization of at least 85 percent. The amount of water needed for demister washing is reduced significantly but small amounts are required intermittently to prevent scaling. Lime scrubbers easily achieve 85 percent alkali utilization. Limestone systems, however, normally operate at 60-70 percent utilization, and this helps explain why they tend to plug. The Shawnee tests show that limestone utilization can be increased to 90 percent by using three reaction tanks in series instead of the usual single tank. Alternately, the amount of limestone can be reduced until the pH of the slurry entering the scrubber is about 5.2. Although utilization will then increase, scrubbing efficiency will go down. Efficiency can be restored by increasing the liquid to gas flow rate ratio, by increasing the scrubber pressure drop, or by adding magnesium oxide to the scrubbing medium. Some added benefits from operating at low pH include decreased limestone makeup costs and decreased sludge formation.

Corrosion and erosion have also been serious problems at some FGD installations where recycle pumps, I.D. fans, piping, and reheaters have suffered considerable damage. Highly resistant alloys are available for construction materials, but plants have tended to select less costly materials where possible. Rubber coatings have been effective against both corrosion and erosion. Pumps, fans, and pipes can all be rubber coated. Reheaters can also overcome corrosion problems as discussed below.

Demister sections separate most of the absorbing solution from the cleaned gas, but some entrained droplets pass through to the atmosphere. The droplets are acidic because they contain dissolved SO_2 and can be very corrosive to fans and stack linings. It is therefore desirable to reheat the clean gas to evaporate the droplets. Reheat may also be required, to keep the plume from drooping to the ground. The need for flue gas reheating will be evaluated in detail

in an upcoming EPA study.

Several satisfactory reheat methods are available. Perhaps the simplest is to bypass part of the flue gas around the scrubbers. The bypassed portion, which remains hot, is combined with the main flue gas stream downstream of the scrubbers. This approach is satisfactory when emission limitations can be met by scrubbing only part of the flue gas. These circumstances may exist when low sulfur fuel is burned and when the entire gas stream is treated in an electrostatic precipitator.

Another simple reheat method is to install gas burners in the duct. The heat generated by burning the natural gas directly reheats the flue gas. Oil burners can also be used if natural gas is unavailable.

Another reheating method uses hot air blown into the gas duct. As the hot air mixes, heat is transferred to the cool gas. The hot air can be obtained from a steam heat exchanger.

Another reheat method involves the installation of steam heat exchangers in the gas duct. These units are bundles of small tubes located downstream of the absorber. Steam passes through the tubes and heats the gas flowing by the outside. At some plants, these reheaters have been corroded by acid and chlorides.

The acid attack results from acidic water droplets that condense on the reheater tubes. The upstream tubes contact unheated gas and are the most susceptible to damage. Experience has shown that ordinary carbon steel and 304 stainless steel are likely to be unsuitable; 316L stainless steel, however, appears to have a satisfactory life.

The mechanism of chloride attack is less well understood, and may result from reactions with components of the flue gas or by scale formations on the tubes. The damage first appears as tiny pits along the tubes, which grow into holes. The holes can be welded closed but eventually the tube fails. The best choice of material to resist chloride attack is still to be determined. Highly resistant materials are available, but plants prefer the less expensive alloys such as 316L stainless. At the present time it is safer to use direct reheat (gas or oil burners) rather than tube reheaters if the flue gas is to be

recycled directly.

The operating experience of FGD systems is summarized in Appendix A. Three of the lime and limestone systems - Paddy's Run, Shawnee, and La Cygne - provide the clearest demonstration of technical feasibility. These plants have demonstrated good SO_2 removal efficiency (80 percent and higher) and good equipment reliability (80 percent and higher) over extended time periods.

The issue of sludge production in lime and limestone FGD systems has been addressed by EPA in conjunction with a D.C. Circuit Court remand in litigation involving New Source Performance Standards for power plants (10). On the basis of testimony at the National Hearings, the findings of the EPA SCRUBBER panel, several contract studies, and the record of adjudication hearings held in Ohio on SO_2 emission regulations, EPA has concluded that the adverse environmental impact of sludge disposal can be avoided at reasonable cost by fixing the sludge, or by using alternate FGD technology that does not produce sludge.

EPA recognizes that large quantities of sludge will be produced by lime or limestone scrubbing systems. Disposal methods must therefore be carefully selected to minimize adverse effects on the environment. Based on available information, methods of disposing of sludge in an environmentally acceptable manner are now offered commercially at reasonable cost. In these methods the sludge is fixed (hardened) and used as landfill.

EPA is investigating possible alternatives to chemical sludge fixation. One approach is to oxidize the sludge to convert the calcium sulfite to gypsum (calcium sulfate), which is then dewatered. The dry gypsum is physically stable. Unless leachates are a problem, further treatment may not be needed.

In the second approach being examined, sludge is dewatered and deposited in layers, with fly ash between layers. This arrangement improves drainage and may keep the sludge from rewatering excessively. The pond should be constructed to allow for underdrainage. Drainage water could be recycled to the scrubber.

Commercial processes to fix sludge are now offered at reasonable cost by several industrial waste handling companies. The processes involve addition of flyash and lime to react with the sludge. The reactions are similar to those employed in the setting of cement and transform the sludge into a hard, durable mass.

The fixed sludge can be deposited as landfill material on or off the power plant property. Landfill material such as fixed sludge is frequently needed to reclaim land areas degraded by industrial and commercial operations. In many areas of the United States, for example, power plants obtain their coal from nearby strip mines. Large quantities of fill material are needed to restore the mined areas. Columbus and Southern Ohio Generating Co. has contracted for sludge fixation at their Conesville station. The fixed sludge will be used initially to landfill an area adjacent to the plant. This area will be used for expansion of the station.

Fixing the sludge will greatly reduce its environmental impact. Land degradation can be avoided by covering the fixed sludge with earth when the disposal area is full. Groundwater pollution, a potential problem if soluble chemical materials are leached from the sludge, is also minimized by fixation. If the small amount of leachate from fixed sludge is considered a problem at a specific plant, the landfill can be constructed with a drainage system to collect and isolate the leachate for treatment.

Sludge disposal has been considered in comparison with the alternative of uncontrolled sulfur dioxide emissions. The possible adverse health effects of sludge are heavily outweighed by the serious health effects of sulfur dioxide.

EPA is conducting a field test on sludge disposal at the Tennessee Valley Authority's Shawnee Power Station. Five ponds, 0.1 acre each, were filled with sludge between October 1974 and April 1975. Three ponds received chemically treated sludge and two ponds were filled with untreated sludge. At all the ponds, tests are being run on the supernatant water, the leachate, and the groundwater. Testing will continue through 1977, but interim results have been reported (11).

The interim results show that concentrations of calcium, sulfate, chloride, heavy metals, and total dissolved solids in the leachate from the untreated ponds are increasing towards the concentrations in the input liquor. Leachate concentrations from the treated ponds also increase with time, but approach levels only about half as high as the respective concentrations from the untreated ponds. For example, seven months after sludge deposition the total dissolved solids concentration in the leachate was about 7500 milligrams per liter from Pond A (untreated) and about 3000 milligrams per liter from Pond E (treated). The concentrations in the input liquor were 8285 and 9245 milligrams per liter respectively.

Groundwater analysis before and after sludge placement show no evidence of altered quality so far. The pond floors, however, are clay with very low permeability (about 0.1 inch per year). Therefore, it may be too early to detect possible contamination. The tests will continue.

Sludge fixation operations have been carried out at several power plants. Although the operations have been limited in extent, they have demonstrated that the processes work. The practice is now expanding as plants incorporate more full scale fixation operations. Full scale operations are summarized below:

a) Commonwealth Edison fixes half the sludge from its 167 MW Will County Station limestone scrubber by adding lime and flyash. Concrete mixing trucks transport the sludge to an on-site pond for disposal.

b) Duquesne Light has employed the Dravo process at its Phillips Station sludge from its 410 MW lime scrubbing system. After the sludge hardens in temporary on-site disposal ponds, it is excavated and trucked to a permanent site. The present site is nearly full, and a contract has been negotiated with I.U. Conversion Systems to handle the sludge in the future. I.U. Conversion will be responsible for the entire operation; they will receive the sludge, fix it, and then place it in a landfill.

c) Duquesne Light's Elrama Station has also contracted with I.U. Conversion Systems for sludge management. A portion of the sludge equivalent to 200 MW will be fixed.

d) Pennsylvania Power has contracted with Dravo Corporation for management of the sludge at the new Bruce Mansfield plant. The sludge from this 835 MW unit is pumped several miles to a ravine. The sludge is treated before being placed in the ravine.

e) Columbus and Southern Ohio Electric Co. plans to start up its new 400 MW Conesville No. 5 unit in late 1976. The sludge will be fixed with I.U. Conversion System's process.

f) A demonstration project was conducted at Southern California Edison's Mohave plant. Portions of the plant sludge were treated with the I.U. Conversion Systems process.

B. Wellman-Lord Systems

The Wellman-Lord System uses a solution of sodium sulfite (Na_2SO_3) to remove SO_2. The spent absorbing solution is regenerated by heating, and then recycled to the absorber. During regeneration, a concentrated stream of SO_2 is produced and can be further processed to liquid SO_2, sulfuric acid, or elemental sulfur. The first two alternatives require a dependable market, since the product is difficult to store. The third alternative is the most generally desirable, because elemental sulfur can be stockpiled or sold.

Some of the sodium sulfite scrubbing agent in Wellman-Lord units is unavoidably oxidized to sodium sulfate. To prevent buildup of the unreactive sulfate, a purge stream is removed for treatment. By controlled crystallization, the sulfate is removed from the purge stream, and the remaining liquor is recycled to the absorber; the crystallized sodium sulfate is dried for sale or disposal. Alternatively, the sodium sulfate could be treated to regenerate sodium sulfite. Two such processes have

been tested at the pilot plant level, and are reportedly ready for full scale installation (12).

The Wellman-Lord System was developed by Davy Powergas in the 1960's. Seventeen full scale units are now operating in the United States, Japan, and West Germany. The units are installed on nine oil-fired boilers, five Claus plants and three sulfuric acid plants. Of thirteen planned installations, six will be installed on coal-fired power plants. A complete list of Wellman-Lord systems is given in Appendix B, Tables B-2, B-3, and B-4.

In 1973 EPA and Northern Indiana Public Service Company (NIPSCo) agreed to share the capital cost of installing a Wellman-Lord demonstration unit at the Mitchell power plant in Gary, Indiana. The unit has been constructed and is now in its startup phase. SO_2 recovered in the Wellman-Lord unit will be treated by the Allied Chemical reduction process to produce elemental sulfur.

The NIPSCo system is significant because it is the first application of the Wellman-Lord process to a coal-fired boiler. The high ash content of coal compared to oil required more thorough cleaning of the gases upstream of the scrubber. At the NIPSCo unit, an existing electrostatic precipitator will be used. It is expected that the gases leaving the precipitator will be as acceptable to the Wellman-Lord unit as gases from oil-fired boilers. To monitor the performance of the NIPSCo unit, EPA has contracted with TRW to conduct tests during the first year of operation. TRW has installed an automated test system to continuously record boiler and FGD system data. A private company has been hired by EPA to prepare a documentary film on the new FGD system.

Wellman-Lord systems approach the optimum goal, namely to extract sulfur in the form of elemental sulfur or some other valuable product with no significant waste streams. The seventeen units in operation have accumulated a total of more than 57 years of operation and SO_2 removal efficiency is reported to be over 90 percent in normal operation at all installations (12). The reliability of the Wellman-Lord units is also reported (12) to be high with on-stream times

exceeding 97 percent on the Claus and acid plants in the United States and exceeding 98 percent on the oil-fired boilers and Claus plants in Japan. (Note: reported on-stream times are for the absorption area only.)

C. Double Alkali Systems

Double alkali systems use two alkalies - one for absorbing SO_2 and one for regenerating the spent absorbing liquor. Many alkali combinations are possible, but a sodium alkali such as sodium hydroxide or sodium sulfite is usually the absorbing agent, and a calcium alkali (lime or limestone) is usually the regenerating agent. In a typical system, SO_2 from flue gas is absorbed by a solution of sodium sulfite, which is thereby converted to sodium bisulfite. The spent scrubbing liquor is pumped to a tank and treated (usually) with lime. The reactions in the tank produce sodium sulfite and calcium sulfite:

$$2NaHSO_3 + Ca(OH)_2 \longrightarrow Na_2SO_3 + CaSO_3 + 2H_2O$$

The insoluble calcium sulfite settles out as a waste solid and the soluble sodium sulfite solution is recycled to the scrubber.

Double alkali systems were developed largely to avoid the scaling problems associated with lime and limestone systems. Scaling tends to occur in the lime and limestone systems because the calcium compounds formed in the scrubber are relatively insoluble and easily precipitate out of solution as a scale. The problem is reduced in double alkali systems by using a soluble sodium alkali in the absorber; the sodium compounds formed are soluble and therefore the scrubbing medium is a solution instead of a slurry, as in the case with calcium. The main purposes of the second alkali in the double alkali system (lime or limestone) are to lower operating costs and to produce an insoluble throwaway waste product. Since the sodium alkali is relatively expensive, it is more economical to regenerate the spent

scrubbing liquor with lime or limestone than to purchase fresh sodium alkali. Also, the calcium end product is more environmentally acceptable than a soluble sodium waste.

In addition to having lower scaling potential, double alkali absorbers are more efficient than their lime-limestone counterparts, because the sodium alkali is more reactive than lime or limestone. As a result, double alkali absorbers can operate with a lower liquid to gas ratio in the absorber, a lower pressure drop in the absorber, and with fewer absorber stages. All of these advantages tend to lower operating cost.

One problem occurring in double alkali systems is the oxidation of sulfite compounds to sulfates in the scrubber. The sulfates are not reactive and must be regenerated to active alkali or removed, to maintain the reactivity of the scrubbing liquor. Regeneration can be accomplished:

a) simultaneously with generation of sodium sulfite by reaction with lime in the regeneration tank,
b) by treating a slip stream with sulfuric acid, or
c) by electrolysis of a slip stream.

Alternatively, sodium sulfate can be removed from the system by allowing sufficient quantities to leave with the solid waste instead of washing the solids to remove the soluble salts. Still another approach is to curtail sulfate formation by such measures as:

a) minimizing residence times in the absorber;
b) minimizing air contact in mixers and solids separation equipment;
c) using high concentration absorbing solutions to limit absorption of oxygen; and
d) bleeding a small stream of liquor to prevent sulfate buildup.

(For a good discussion of these approaches see Reference 11.)

Double alkali systems have undergone extensive development and are now operational on many coal and oil-fired industrial boilers and three Japanese oil-fired utility boilers. A complete list of planned and operating Japanese and American units has been prepared (13) and is reproduced in Table B-5. Table 4 summarizes the current installations.

Table 4. Current Status of Double Alkali Units on Industrial Boilers, Utility Boilers, and Reduction Kilns.

	United States		Japan	
	No. of Units	(MW)	No. of Units	(MW)
Operational	6	(140)	10	(1610)
Planned	4	(1055)	2	(900)
Total	9	(1195)	12	(2510)

Technical advantages and projected costs of double alkali systems indicate that they will probably be a viable alternative to lime and limestone systems. This conclusion is based on the following:

1) At least four United States companies offer the system commercially: FMC Corporation, Combustion Equipment Associates, Zurn, and Envirotech Corporation.
2) Because the sodium alkali scrubbing reagent is more reactive than lime or limestone, SO_2 removal efficiencies of double alkali units can be higher. The FMC units are designed to exceed 90 percent efficiency (14).

3) The use of sodium alkali instead of lime or limestone lessens the possibility of scaling and therefore increases system reliability. FMC Corporation reports (14) reliabilities of 90 percent and higher for its pilot plants and commercial installations (listed in Table B-5).
4) Costs are competitive with lime and limestone systems. Recent EPA estimates of capital and operating costs are $50-$60 per kilowatt and 2.5-3 mills per kilowatt-hour respectively (13).

In order to demonstrate the feasibility of double alkali systems on coal-fired boilers in the United States, EPA decided to fund a 100 MW or larger demonstration unit. After receiving several bids, EPA contracted with Louisville Gas and Electric; the utility will now install a double alkali system on its 277 MW Cane Run No. 6 unit.

b. Chiyoda Systems

Chiyoda International Corporation, a Japanese firm, has developed an FGD system based on scrubbing with dilute sulfuric acid. The system is called the Chiyoda Thoroughbred 101 (CT-101) and has been installed on thirteen commercial boilers in Japan. A list of the installations is included in Appendix B in Table B-6.

The system has been described in a Chiyoda report (15). Flue gas is pretreated in a venturi scrubber to remove particulates and chlorides, and then treated in a packed tower with dilute sulfuric acid (about 2 percent acid by weight). The SO_2 from the gas dissolves in the absorbing solution and forms sulfurous acid:

$$SO_2 + H_2O \longrightarrow H_2SO_3$$

The absorber liquid leaving the absorber section is pumped to an oxidizing tower where air is blown in. A ferric ion catalyst (in the form of iron sulfate dissolved in the absorber liquid) converts

sulfurous acid to sulfuric acid:

$$H_2SO_3 + 1/2\ O_2 \xrightarrow[Fe^{+++}]{} H_2SO_4$$

Most of the absorber liquid leaving the oxidising section is recycled to the absorber, but a portion is bled to a crystalliser and treated with limestone. The reaction in the crystalliser produces gypsum as a precipitate:

$$H_2SO_4 + CaCO_3 \longrightarrow CO_2 + H_2O + CaSO_4$$

Gypsum is removed as the final end product in a centrifuge or vacuum filter. In the overall process therefore, SO_2 is converted to sulfuric acid and then removed as gypsum ($CaSO_4 \cdot 2H_2O$).

According to Chiyoda reports, the systems installed to date have established an impressive record. As shown in Table B-6 (appendix), the thirteen units installed so far have had availabilities of 94-100 percent while accumulating 20 years of operating experience. The units have also shown SO_2 removal efficiencies of over 90 percent (16).

All of the Japanese units are oil-fired because of the scarcity of coal. To demonstrate the Chiyoda system on a coal-fired plant, a 33 MW unit has been constructed at the Scholz plant operated by Gulf Power Co. in Florida. The most recent report gives a detailed operating history of the first year's operating history ending December, 1975 (15). A variety of start-up problems resulted in an availability for the scrubber of only 60 percent during 1975. Most of the problems causing shutdown were easily repaired and system availability increased to 97 percent for the last 3 1/2 months.

SO_2 removal efficiency in the pilot plant averages about 82 percent (15) which is less than the 90 percent reported in Japan.

Overall, the pilot plant experience is encouraging and shows that the Chiyoda system can be successfully applied to a coal-fired boiler.

E. Magnesium Oxide Systems

Magnesium oxide systems have been developed to take advantage of the high reactivity of magnesium oxide. These systems offer greater removal efficiencies than the less reactive lime or limestone based systems.

Magnesium systems are the least expensive of the regenerable systems. They can be less costly than lime or limestone if sludge fixation is required.

To make magnesium oxide systems economical, the expensive magnesium compounds must be recovered for recycle. As a result, magnesium oxide systems are designed as regenerable systems. In all three systems constructed to date, the same regeneration method has been employed. Magnesium sulfite, the end product of the reactions, is precipitated from the spent absorber liquor, dried, and sent to a sulfuric acid plant. At the acid plant, the magnesium sulfite is roasted to drive of SO_2 and regenerate magnesium oxide. The SO_2 is converted by standard processes into sulfuric acid, a salable product.

Full scale operation has been demonstrated at two facilities; Boston Edison's Mystic Station, and Potomac Electric's Dickerson Station. A third system has been briefly operated by Philadelphia Electric at its Eddystone Station.

The 150 MW Mystic unit burns 2.5 percent sulfur oil. The FGD retrofit unit started up in April of 1972 and was operated until June 1974, when EPA funds for this demonstration program ran out. Operation during this period was intermittent because of various equipment problems; during the last four months however, the unit's availability averaged 76 percent.

A magnesium oxide system was also installed at Potomac Electric Power's Dickerson Station. This station burns coal containing about 3 percent sulfur. The regeneration facilities were located at the Essex Chemical Corporation sulfuric acid plant

in Rumford, Rhode Island. The spent and regenerated chemicals were transported between the two sites by truck.

The Dickerson retrofit FGD unit started up in September 1971 and shut down in August 1975 when the Essex Chemical plant was closed. With no facilities for regenerating magnesium oxide, the FGD operation would have become very expensive.

The operation of the Dickerson FGD system has been described (17, 18). The scrubber operated intermittently due to various hardware problems, modifications, unavailability of regeneration facilities at the Essex Chemical plant, and boiler downtime (17).

The major hardware problems involved corrosion and erosion of piping and problems in the slaking and injection of magnesium oxide. Although these problems resulted in considerable downtime, the solutions appear to have been worked out. Rubber linings were found to withstand the corrosion-erosion in the first stage piping and should be satisfactory in the second stage also. Magnesium oxide handling problems were solved by installing a pre-mix tank and high speed agitator (17).

The important features offered by magnesium oxide systems include low scaling potential, high SO_2 removal efficiency, and salable end product. No scaling was observed in the Dickerson absorber (17) and SO_2 removal efficiency was consistently above 90 percent. In summing up the process the operator reports:

> "The process has demonstrated that it can achieve a 90 percent or better SO_2 removal efficiency. It can produce commercially salable sulfuric acid, and MgO can be recycled and used in the absorber."

The third magnesium oxide system installed to date is at Philadelphia Electric's Eddystone Station (19). This system was retrofitted to a 300 MW boiler burning 3.3 percent sulfur coal. Only one-third of the boiler off-gases are treated, so the FGD unit is sized for 105 MW.

The regeneration system was originally located at the Olin

Chemical Sulfuric acid plant in Paulsboro, New Jersey. Shortly after the FGD began operation, Olin closed the plant leaving Bibystone with no facilities for regeneration, so the scrubbers were eventually shut down. The Bibystone facility operated intermittently between September and October 1975 and generated 30 tons of magnesium sulfite. During this time magnesium oxide was regenerated by Olin and recycled through the Bibystone system. FGD system will soon be able to resume operations because of a recent 3-year agreement signed with Essex Chemical that provides regeneration facilities at a Newark New Jersey plant.

IV COSTS

The costs of installing and operating FGD systems are significant. They are an important factor in determining whether FGD systems will be installed and in the selection of a particular FGD type. Unfortunately, the costs reported by different sources vary considerably. This is caused by several factors including site-specific requirements, extent of equipment redundancy, items included in cost basis, item costs, and inflation.

Cost figures from several sources are discussed in Appendix C. A short summary is given in Table 5. Costs at specific plants, that do not conform to the Table 5 cost basis, may vary considerably.

The capital cost figures in Table 5 indicate the cost of installing an FGD system. The 500 MW (500,000 kilowatt) limestone system, for example, would cost (68.4 $/kw)(500,000 kw) or $34.2 million.

The operating costs in Table 5 indicate the cost of operating the FGD system (or the additional cost of burning low sulfur coal). The operating cost includes a pro rata share of the installation cost. That is, the installation cost is amortized over the plant lifetime. In the above example, the operating cost of the limestone system is 3.41 mills per kilowatt-hour of electric energy produced.

The cost of electric power is reported annually by the Federal Power Commission. The most recent report gives the January 1, 1976 figures (23). On that date, the national average for residential customers consuming 500 kilowatt-hours per month was 38.5 mills per kilowatt hour. This rate will increase over time as a result of automatic fuel cost adjustments and rate changes approved by regulatory commissions. Assuming that fuel cost remain stable and that authorized rate increases parallel an inflationary rise

Table 5. Costs of FGD Systems and Low Sulfur Coal

System	Capital Cost $/kw	Operating Cost mills/kwh	Basis	Reference
Limestone	68.4	3.41	Coal-fired power unit	20
Lime	61.1	3.65	90% SO_2 removal: on-site solids disposal	20
Magnesium Oxide	71.7	4.02	500 MW, new, 3.5% Sulfur	20
Wellman-Lord	84.8	5.37	30 years life see also notes a,b,c,d for capital costs, and e,f, for operating costs.	20
Double Alkali	50-60	2.5-3	Coal-fired power unit 200 MW or larger new or simple retrofit 3-4% Sulfur 80% load factor lime at $30-$33/ton soda ash at $65-$70/ton excluding sludge fixation	13
Chiyoda	76		Coal-fired power unit 90% SO_2 removal, 90% particulate removal 500 MW plant, 2 1/2 Sulfur 200°F gas reheat (oil)	15
Low Sulfur Coal	20	4-7	Incremental cost due to low sulfur fuel. Operating cost covers increased fuel and transportation costs.	21,22

Table 5 Continued; Notes:

a) Midwest plant location represents project beginning mid-1975, ending mid-1978. Average cost basis for scaling, mid-1977. Minimum in process storage; only pumps are spared. Investment requirements for disposal of flyash excluded. Construction labor shortages with accompanying overtime pay incentive not considered.

b) These investment costs depend heavily on project definition.

c) Working capital has been included in the total capital investment.

d) Sludge disposal pond with clay liner.

e) Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1978 revenue requirements. Investment and revenue requirements for disposal of flyash excluded.

f) These revenue requirements reflect capital investments shown in this table; byproduct credit and sludge fixation costs excluded.

of seven percent annually, the average 1978 residential rate will be about 44.1 mills per kilowatt-hour.

The FGD operating cost in the above example was based on 1978 dollars, assuming an inflationary rate of seven percent per year. Comparison shows that the FGD operating cost is about 7.7 percent of the average 1978 residential rate. If FGD costs are passed on to consumers, the average rate increase will be significantly less than 7.7 percent. This is because all power plants will not need FGD equipment. Much of this country's power is produced by hydroelectric plants, nuclear plants, and plants that burn gas or low sulfur oil.

If a plant burns low sulfur coal instead of installing FGD equipment, capital and operating costs may be higher than if regular coal were burned. These incremental costs vary widely and in some situations can exceed the cost of operating FGD equipment.

Incremental capital costs associated with low sulfur coal have been estimated to be $20 per kilowatt (21). This includes coal handling, combustion system modifications, and upgrading of electrostatic precipitators. The last item is needed because low sulfur coal generates a fly ash with high electrical resistivity.

The incremental operating costs from burning low sulfur coal result from increased coal costs, increased hauling distances and decreased heating value. The operating cost increase is difficult to specify because it depends on various site specific conditions. One recent (1975) analysis is based on purchasing low sulfur Wyoming coal for $7 per ton and transporting it to St. Louis for $10-$13 per ton. Because of its low heating value, nearly twice as much low sulfur coal would be needed, bringing the equivalent price to $35 ($45 if transported to Philadelphia). This results in an incremental operating cost of 4-7 mills per kilowatt-hour (22).

APPENDIX A

OPERATIONAL OVERVIEW

This Appendix reviews the FGD systems installed in United States power plants and classified as operational. The Scholz and Shawnee installations are pilot plants. Eddystone and Stock Island are not currently operating but could be restarted. Valmont is designed principally for particulate removal but has some SO_2 removal capability. The operational units are:

1. Bruce Mansfield
2. Cane Run
3. Chulia
4. Colstrip 1 and 2
5. Eddystone
6. Elrama
7. Four Corners
8. Green River
9. Stock Island
10. Hawthorn 3 and 4
11. La Cygne
12. Lawrence 4 and 5
13. Paddy's Run
14. Phillips
15. Reid Gardner 1, 2 and 3
16. St. Clair
17. Scholz 1B and 2B
18. Shawnee 10A and 10B
19. Sherburne
20. Valmont
21. Will County

1. Bruce Mansfield

Pennsylvania Power Company
Shippingport Pennsylvania
Coal-Fired: 4.3 Percent Sulfur
Unit No. 1: 831 MW New Installation
Lime Scrubbing
Chemico
Startup: April 1976

The Bruce Mansfield plant is a 2700 MW three unit, coal-fired facility located on the Ohio River in the borough of Shipping Port, Pennsylvania. This new facility is being built by Pennsylvania Power Co., in conjunction with Cleveland Electric Illuminating Co., Duquesne Light Co., Ohio Edison Co., and Toledo Edison Co. Unit No. 1 now has an operational FGD system. Units 2 and 3 will also have FGD systems. Emission control equipment for Unit No. 1 is designed to meet State emission regulations of 0.6 lb SO_2 per million BTU of heat input and 0.0175 grains per standard cubic foot of particulate when burning 11,900 BTU per pound of coal having average ash and sulfur contents of 12.5 and 4.3 percent. The system consists of six parallel trains, any five of which can handle the full boiler load. Each train consists of two venturis in series. Lime slurry containing 3 - 6 percent MgO is the scrubbing medium.

The scrubber sludge is combined with a fly ash slurry from the boiler and pumped to a 200 foot diameter thickener. Sludge from the thickener is then pumped to a waste disposal system where it is mixed with a stabilizing agent (Calcilox) and then pumped approximately 7 miles to the Little Blue Run ravine for land fill.

The power station began full commercial operation in April 1976. The last scrubber train was put on line in May 1976. The system has operated well. Total system reliability for May and June 1976 was 100 percent.

2. Cane Run

Louisville Gas and Electric Company
Louisville, Kentucky
Coal-Fired; 3.5 - 4.0 Percent Sulfur
Unit No.4; 178 MW New Installation
Lime Scrubbing
American Air Filter
Startup, August 1976

The Cane Run power station is operated by the Louisville Gas and Electric company and located in Louisville, Kentucky. The plant consists of six electric power steam generating units having a total steam turbine net generating capacity of 992 MW.

Unit No. 4 is a coal-fired steam generating boiler with a continuous net generating capacity of 178 MW. The unit has a maximum power generation capacity of 190 MW. The unit heat rate is 10,030 BTU/kwh. The boiler is currently burning coal with a gross heating value of 11,500 BTU/lb and average sulfur and ash contents of 3.5-4.0 percent and 11.0-12.0 percent, respectively.

The emission control system for this unit consists of an electrostatic precipitator (ESP) upstream of a wet scrubbing system. The ESP provides primary particulate control while the wet scrubbing system provides additional particulate removal and primary sulfur dioxide control.

The Flue Gas Desulfurization (FGD) system consists of two identical parallel scrubbing trains designed and installed by the American Air Filter (AAF) Company. The wet scrubbing system utilizes a slurry of carbide lime for sulfur dioxide removal from the flue gas. The carbide lime is a waste by-product obtained from a nearby acetylene manufacturing plant. The hydrated lime contains 90.0 to 92.0 percent calcium hydroxide, 2.0 to 2.5 percent silica, 3.0 to 8.0 percent calcium carbonate, and 0.1 percent magnesium oxide.

Each scrubbing train is equipped with a guillotine-type by-pass damper allowing by-passing of the gas around the scrubbers. Each scrubbing train contains the following major pieces of equipment: I.D. booster fan, quench section, flooded elbow, mobile bed contactor, centrifugal demister, and a 3-section reactant tank system. The waste disposal system consists of a 75-foot diameter thickener for liquid-solids separation and a fly ash pond for ultimate disposal of the thickener underflow. The scrubbing wastes are stabilized with fly ash and water is recycled back to the process. The system does not use a stack gas reheat system.

3. Cholla

Arizona Public Service
Joseph City, Arizona
Coal-Fired: 0.44-1 Percent Sulfur
Unit No. 1: 115 MW, Retrofit
Lime/tone Scrubbing
Research Cottrell
Startup, October 1973
Unit No. 3: 250 MW, New
Limestone Scrubbing
Research Cottrell
Startup, June 1977

The Cholla station is described in an EPA report (24).

The station is currently being expanded; at present only the 124 MW (Number 1 unit is operating, burning coal containing about 0.6% sulfur. A two-module limestone FGD system was retrofitted behind existing cyclone dust collectors by Research Cottrell. Each module consists of a flooded disc particulate scrubber followed by an SO_2 absorber. The Module A absorber is packed with a honeycomb of corrugated polypropylene; the Module B absorber is unpacked.

Banks of steam tubes are installed in the gas duct downstream of the absorbers to reheat the gas. This is done to protect the stack lining from acid corrosion. In the past, condensation droplets forming on the Module B duct walls fell onto the ends of the reheater tubes and acid corrosion occurred. This problem has been solved by insulating the duct (to inhibit condensation) and providing small troughs to divert the droplets. Fortunately, the original tubes could be repaired by cutting off the corroded tips.

Pitting of the reheater tubes, apparently due to chloride attack, has also occurred. The pits tend to grow into small holes causing steam leaks. This chloride corrosion can be curtailed by keeping the tubes clean and free of scale buildup. When holes form, the tubes can be blanked off or the holes welded shut. Eventually the tubes will wear out but so far have provided 18 months of service.

The operation of the FGD system has a good record of reliability. For the period from January 1974 until August 1976 the reliability of the FGD system has been 92 percent (Module A) and 87 percent (Module B). Regular maintenance has been required, estimated by the plant at about 30 manhours per day. A very similar system is being installed on the 250 MW Unit 2, now under construction.

4. Colstrip

Montana Power Company
Colstrip Montana
Coal-Fired: 0.8 Percent Sulfur
Unit No. 1: 360 MW New Installation
Lime/Alkaline Flyash Scrubbing
Combustion Equipment Associates
Startup, October 1975

Unit No 2; 360 MW New Installation
Lime/Alkaline Flyash Scrubbing
Combustion Equipment Associates
Startup, July 1973

The Colstrip plant is a mine mouth installation. Unit No.1 is now operating at full commercial capacity. Operating data accumulated to date are being evaluated by the utility for presentation to state regulatory agencies.

5. Eddystone

Philadelphia Electric Company
Eddystone Pennsylvania
Coal-Fired; 2.5 Percent Sulfur
Unit No. 1A; 120 MW Retrofit
Magnesium Oxide Scrubbing
United Engineers
Startup, September 1975

Eddystone is the third (and most recent) plant to install a large scale magnesium oxide scrubber system. The plant has no facilities of its own for regeneration, but will depend instead on the Essex Chemical plant in nearby Newark, New Jersey to regenerate the spent scrubbing liquor. The Olin Chemical plant which was formerly used, permanently ceased operations shortly after the Eddystone scrubber became operational. FGD operations at Eddystone have stopped until the new regeneration facilities are established. From September to October 1975, before the Olin plant closed down, the Eddystone FGD systems operated intermittently and generated 30 tons of magnesium sulfite. Regeneration and recycling were carried out successfully.

The Eddystone station is described on a EPA report (19).

6. Elrama

Duquesne Light
Elrama Pennsylvania
Coal-Fired; 1.0-2.0 Percent Sulfur
Units No. 1,2,3,4; 501 MW (Total) Retrofit
Lime Scrubbing
Chemico
Start-up, October 1975.

The Elrama FGD system is nearly identical to that at the Phillips station. Mechanical collectors and a precipitator remove most of the particulates, and 5 single stage parallel scrubbers remove SO_2.

There are 4 boilers at Elrama, with a total capacity of about 500 MW. So far only two boilers have been tied into the FGD system. The first FGD unit began operating in October 1975. Startup had been delayed until operating problems at the similar Phillips installation could be partially worked out. So far, four FGD units have been brought on line; the remaining unit is being kept out of service to install rubber-lined recycle pumps in an effort to overcome corrosion and erosion of pump impellers, which remain a problem with the unlined pumps at Phillips.

The sludge produced at Elrama is being fixed by the I.U. Conversion System process.

7. Four Corners

Arizona Public Service
Farmington, New Mexico
Coal-Fired; 0.7 Percent Sulfur
Unit No. 5A; 160 MW Retrofit
Lime Scrubbing
Southern California Edison
Startup, February 1976

The Hunter 5 boiler is a large 755 MW unit, and will eventually be entirely controlled. Initially, about 20 percent of the off gas is being treated in a test unit. From the results of this test, a unit will be designed for the remaining off gas.

The test unit is the horizontal line system that was developed and tested at Southern California Edison's Mohave plant. This unit was dismantled, and reconstructed at Four Corners. Installation was completed in February 1976. Shortly afterwards the boiler was taken off-line for overhaul. As of August 1976 the boiler has not returned to service.

8. Green River

Kentucky Utilities
Central City, Kentucky
Coal-Fired; 3.8 Percent Sulfur
Units No. 1 and 2; 64 MW Retrofit
Lime Scrubbing
American Air Filter
Startup, September 1975

This power station consists of two power generating units and four boilers. The power generators are peak loaded. The boilers providing steam to the generators are normally operational 5 days per week, with one or more often operating at reduced capacity.

The SO_2 and particulate control systems for boilers 1, 2 and 3 consist of mechanical collectors and a tail-end lime scrubbing system. The FGD system consists of one module designed to handle a maximum gas capacity of 360,000 ACFM at 300 °F.

The flue gas is drawn through a guillotine-type isolation damper

and duct system to the scrubber fan. The gases then flow through an adjustable-throat venturi scrubber primarily for particulate removal. SO_2 is removed by reaction with the lime slurry in a mobile bed contactor, which consists of ten compartment sections with overhead slurry sprays and underbed dampers to accommodate gas volume turndown.

The slurry/recycle system consists of a partitioned reactant tank with recycle pumps for supplying the contactor and Venturi, a lime slurry slaker and feed system, and a bleed system discharging to a settling pond. Return water from the pond is used as primary make up.

This system began operating in September 1975 and has compiled a good operating record despite various hardware problems. The logging of operating data began in December 1975 and from that date through August 1976 the average reliability was 80 percent.

9. Stock Island

Key West Utility Board
Key West, Florida
Oil-Fired; 2.4 Percent Sulfur
Unit No. 1; 37 MW New Installation
Limestone Scrubbing
Burn Air Systems
Startup, October 1972

The utility board of the city of Key West operates an oil-fired 37 MW power plant on Stock Island, adjacent to the island city of Key West. An FGD system has been installed but Florida State regulations do not require its operation. For this reason it is unlikel, that the FGD system will ope ce in the future, except possibly for tests.

The FGD system uses pulverized c..al and seawater. The coral

is initially ground to a fine powder in a roller mill crusher, then mixed with seawater to form a dilute dioxide. The cleaned gas is discharged to atmosphere and the spent slurry is pumped to a settling pond. The clarified seawater is discharged into the sea. The system is not generally applicable because it uses coral and no water recycle.

The two scrubber modules are designed to handle a combined total of 126,950 CFM at 150°F. Flue gases from the boiler are drawn through an induced draft fan and forced either through the bypass duct or through one or more FGD modules via three sets of dampers between the induced draft fan and the stack. Before entering the scrubbing system the gas is cooled from 350 °F to 160 °F by seawater sprays. This cooling protects the fiberglass components of the FGD modules. A pressure drop of 12 to 14 inches of water gauge is the normal operating range.

The FGD system was placed in operation October 1973. Stable operation was never obtained. The scrubbers were shut down in January 1975 and have not been restarted. A 2-month test run may be conducted in the latter part of 1976.

10. Hawthorn

Kansas City Power and Light
Kansas City, Missouri
Coal-Fired; 0.6 - 3.0 Percent Sulfur
Unit No. 3; 140 MW Retrofit
Limestone Injection
Combustion Engineering
Startup, November 1972
Unit No. 4; 100 MW Retrofit
Limestone Tail-End Wet Scrubbing
Combustion Engineering
Startup, August 1974

The Hawthorn station is described in an EPA report (25). The FGD systems at Hawthorn are two of the original systems ever put on stream. Both are designed for limestone injection into the boiler. This practice takes advantage of the hot boiler to calcine the limestone to more reactive lime. SO_2 removal occurs partly in the boiler by reaction with solid lime and limestone particles and partly in a marble bed wet scrubber downstream of the boiler. An early problem developed in Unit No. 4 when leaks occurred in the boiler tubes. The lime, flyash, and water set up like concrete and formed a massive plug. Unit No. 4 was subsequently modified to have the limestone injected downstream of the boiler (tail end injection). Unit No. 3, however, operated through 1973 with boiler injection. The utility is presently converting Unit No. 3 to tail end injection.

The Hawthorn scrubbers were designed for simultaneous removal of particulate and SO_2. There is no particulate removal prior to the marble bed scrubber; in fact, the original mechanical collectors were removed when the scrubber was retrofitted to the unit. (Otherwise the limestone would be removed before reaching the scrubber.)

Although a single scrubber is economical, experience shows this design to be impractical. The major operating problems at Hawthorne would be greatly reduced if particulates were removed ahead of the scrubber, as explained below.

Boiler gases can be bypassed around the scrubber through special bypass valves. These valves are easily plugged by the dirty gases, however, and become inoperable. As a result, the scrubber can not be put back on line without shutting down the boiler to clean the bypass valves. This has been the major operating problem at Hawthorn, and accounts for most of the scrubber downtime. A new type of bypass valve has been ordered and will be installed in mid 1976.

The Hawthorn scrubbers have served an important function in that

they helped demonstrate that limestone scrubbing is feasible as a process. In retrospect, however, much can be learned about system design from the problems that surfaced. In fact, major design changes have resulted. Designers now include a particulate collector (either a precipitator or venturi scrubber) upstream of the scrubber, and add the limestone directly to the scrubber (instead of the boiler). Also, new types of bypass valves are used, and spare modules and recycle pumps are installed.

11. La Cygne

Kansas City Power and Light
Linn County, Kansas
Coal-Fired; 5.3 Percent Sulfur
Unit No. 1: 820 MW, New
Limestone Scrubbing
Babcock and Wilcox
Startup, February 1973

The La Cygne station is described in an EPA report (26).

The La Cygne FGD system is an important installation, in that it demonstrates a successful application of limestone scrubbing on a large boiler burning high sulfur coal. The FGD system consists of seven modules. Each module has a variable throat venturi scrubber for particulate removal and an absorber for SO_2 control. The absorber has a sieve tray flooded with limestone slurry, and a fiberglass demister section.

Steam coil heat exchangers are installed in the duct to reheat the gases leaving the scrubber, but the 304 stainless steel tubes are corroded by acid condensation in the coal gas on the downstream side. To protect the tubes, the gas is now preheated by blowing hot air into the duct upstream from the reheaters. Part of the combustion

air is used for this purpose. Since the heater for the combustion air was designed to supply the additional air, there is insufficient combustion air to fire the boiler at full capacity. The original 304 stainless steel tubes are being replaced with 316L stainless steel; if the new alloy does not corrode, the hot air reheat can be eliminated.

The I.D. fans have been a problem area. Originally, the fans vibrated excessively when wet flyash built up on the rotors. The shafts and rotors have been replaced with heavier parts and the fans are now more stable. The fans still get out of balance and at times must be shut down for cleaning and repair. The plant hopes to reduce maintenance further, by reducing scale through better pH control.

Overall, the operating experience with this scrubber has been encouraging. Over the last two and a half years (January 1974 - August 1976) all seven modules have been kept operational. The availabilities of modules A through G have been respectively, 83, 83, 79, 83, 82, 84, and 86 percent. The average for all seven systems was 83 percent. The trend for these units has been towards increasing reliability. Excluding three months when the boiler was down for repairs, the monthly averages from February to December 1976 ranged between 90 and 94 percent.

The SO_2 removal efficiency is also good. Two tests run in 1975 showed that the scrubber modules averaged 71.1 and 80 percent respectively. (8).

12. Lawrence

Kansas Power and Light
Lawrence Kansas
Coal-Fired; 0.5 Percent Sulfur (supplemented with oil and natural gas)

Unit No. 4; 125 MW Retrofit
Limestone Injection
Combustion Engineering
Startup, December 1968

Unit No. 5; 400 MW Installation
Limestone Injection
Combustion Engineering
Startup, November 1971

The Lawrence station is described in an EPA report (27).

Unit No. 4

Unit No. 4 was one of the first full scale FGD units installed on a United States power plant and is the oldest such system still operating. The system is composed of two parallel trains; each train is a single stage marble bed unit and provides both particulate and SO_2 control. Limestone is injected into the boiler and is carried to the scrubber in the flue gas; there are, therefore, no particulate control devices upstream of the scrubber.

The Lawrence scrubbers are very similar to the Hawthorn units. But at Lawrence the spent scrubbing water is routed to a separate reaction tank, instead of the bottom section of the scrubber. The reaction tank was enlarged in 1972, to improve crystallization of calcium sulfite and calcium sulfate.

Plugging remains a major problem. Each scrubber is brought off line twice weekly for cleaning, during the morning when power demand is low. Spray nozzles, which tend to plug, can be cleaned or replaced at the same time.

The plant does not log the operating times of the scrubbers, so

availability figures cannot be reported. System reliability, however, has been good, especially since 1973. In 1974 the FGD system was available for operation 343 days, and in 1974 for 333 days.

Kansas Power & Light plans to replace the entire FGD system in 1977. The new scrubbers will have two stages; a venturi and a spray chamber. An electrostatic precipitator will also be installed.

Unit No. 5

Unit No. 5 is similar to Unit 4 except that it comprises eight parallel modules instead of two, and the total capacity is three times higher.

The No. 5 unit also requires frequent cleaning. The routine maintenance has kept scrubber operability high. In 1974 the system was available for operation 338 days, and in 1975 for 352 days.

13. Paddy's Run
Louisville Gas & Electric Company
Louisville, Kentucky
Coal-Fired; 3.5-4.0 Percent Sulfur
Unit No. 6; 65 MW Retrofit
Lime Scrubbing
Combustion Engineering
Startup, April 1973

The Paddy's Run Station is described in an EPA report (29). The FGD system is installed downstream of an existing electrostatic precipitator and has two parallel modules. Each scrubber module has a marble bed and a chevron demister section. Natural gas burners located in the duct work heat the cleaned gas, preventing condensation in the stack and improving the buoyancy of the gases.

The scrubbing medium is a slurry of carbide lime. Because of the

high efficiency of this system, the liquid to gas ratio can be kept low. The system is operated closed loop; that is, there is no discharge of scrubbing liquids to sewers. Except for water retained by the sludge or lost as moisture from the stack, all the water is recycled to the scrubber.

The lime used in the scrubber is obtained from the waste stream of a nearby plant manufacturing acetylene. Some say this lime (called carbide lime) has special properties that account for the success at Paddy's Run. The argument is that some unidentified compound may inhibit the oxidation of sulfite to sulfate in the scrubber thereby preventing scale formation. There is no good evidence for this. Even if true, the worst result would be that the unknown agent would have to be identified and added to a regular lime system.

At Paddy's Run SO_2 removal efficiency is about 90 percent.

Operation of Paddy's Run has been nearly trouble free (29). Since the boiler is operated only during peak power demands, the entire unit is frequently shut down and restarted. Startups are routine, and the FGD system is easily stabilized. The FGD system has accumulated about one year of operating time.

Very little maintenance is required on the FGD system. Scaling, for example, is completely controlled. Scale does not form unless the pH of the scrubbing liquor gets out of balance; when pH is readjusted the scale disappears. The only permanent scale resulted from a short test using limestone instead of lime. Recycle pumps and the I. D. fans have given steady service, and the fiberglass pipes have resisted corrosion and erosion. The gas burners used for reheat are virtually trouble-free. As a result, the Paddy's Run station is highly reliable and its availability is 100 percent. Louisville Gas and Electric is currently installing identical units at Cane Run (180 and 200 MW units) and at Mill Creek (425 MW unit).

The unit was shut down from February through April 1976 to make modifications in preparation for an upcoming EPA test. During the test the unit will be run with the usual carbide lime to establish normal operation and to investigate changes in operating parameters such as liquid to gas ratio. Then the unit will be run with commercial lime to learn whether this affects performance. Of special interest is whether the unit continues to run without scaling or plugging when commercial lime is used. The tests will also investigate changes in the configuration of the reaction tank and their effects on gypsum supersaturation. The effect of chloride levels on scaling will also be examined by adding chlorides to the scrubbing liquor. Increased levels of magnesium tend to counteract the scaling effect of chlorides and this will also be investigated.

14. Phillips

Duquesne Light
South Heights, Pennsylvania
Coal-Fired: 1.0 - 2.0 Percent Sulfur
Unit No. 1: 410 MW Retrofit
Lime Scrubbing
Chemico
Startup: July 1973

The Phillips plant is described in an EPA report (30).

The Phillips station consists of six small boilers. Each boiler has mechanical collectors and a precipitator. The FGD system consists of four parallel scrubbing trains. One train has two venturis in series; the remaining trains consist of a single venturi. During the initial phase of operations the plant intended to operate only the two-stage train as an SO_2 scrubber. The single stage scrubbers, however, suffer acid corrosion. To raise the pH of the scrubbing medium, lime was added. As a result, all four trains became SO_2 scrubbers.

The plant originally planned to check out the two stage scrubber train and then add second stages to the other three trains. The additional scrubbers were considered necessary to meet the Allegheny County SO_2 regulations. Recently the plant has made trial runs with a more reactive scrubbing agent to determine whether the existing scrubbers are adequate. The new reagent is a type of lime that contains more than the usual amounts of magnesium oxide. Results of these tests are currently being evaluated. (An overall scrubbing efficiency of 83 percent is needed.)

Phillips has experienced prolonged problems with corrosion in their recycle pumps. The original impellers were made of Carpenter 20 alloy; these impellers have a service life of only 1000 to 3000 hours before they need rebuilding or replacement. Other alloys tried have not been significantly better. The plant is now trying rubber lined pumps at a sister installation (Hirams). Since rubber linings have worked at other plants, the prospects seem good.

The sludge handling operation at Phillips is important because it provides a field demonstration of the feasibility of continuous sludge fixation on a large scale. The sludge is separated from the spent scrubbing liquor in large clarifiers, treated with a hardening agent, and deposited in on-site temporary ponds. When the sludge has become firm it is excavated and trucked to a permanent landfill several miles away. The permanent site is a small valley used for years as the disposal area for the boiler ash. The hardened sludge and ash are layered in by bulldozers working on top of the pile. Portions of the valley that fill up are covered with earth, and grass is now growing on some sections. In a year or so, this permanent disposal site will be full. At that time I. U. Conversion Systems will take over complete management of the sludge, fixing it with their own process and placing it in a new landfill. So far, the plant has handled the sludge itself, using Dravo Corporation's treatment process.

15. Reid Gardner

Nevada Power Company
Moapa, Nevada
Coal-Fired; 0.5 - 1.0 Percent Sulfur
Unit No. 1; 125 MW Retrofit
Sodium Carbonate Scrubbing
Combustion Equipment Associates
Startup, April 1974

Unit No. 2; 125 MW Retrofit
Sodium Carbonate Scrubbing
Combustion Equipment Associates
Startup, April 1974

Unit No. 3; 125 MW New
Sodium Carbonate Scrubbing
Combustion Equipment Associates
Startup, July 1976

The Reid Gardner station is described in an EPA report (31).

The Reid Gardner units are the only FGD systems to date that operate with sodium carbonate. They were so designed to take advantage of a nearby supply of trona, which contains about 80 percent sodium carbonate, 20 percent sodium chloride, 10 percent sulfates, and 10 percent insoluble material.

The Reid Gardner plant presently operates three 125 MW boilers. Construction of a fourth boiler, also 125 MW, has been postponed indefinitely. The three operating boilers have nearly identical FGD systems.

Each FGD system consists of two parallel venturis followed by

an absorber. The absorber has a spray system, flooded sieve tray, and a radial vane demister section. Mechanical collectors (multi-cyclones) are installed upstream of the FGD system to remove about 75 percent of the particulates.

The FGD systems operate with an open water loop. About 50 gallons of spent scrubbing solution per minute are withdrawn from the system, neutralized, and discharged to on-site ponds. Apparently nearly all of this water evaporates into the hot dry desert air.

The plant has experienced special problems pumping sodium carbonate slurries. When concentrated, the solution tends to form a slush, as though it were freezing, and cannot be pumped. "Frozen" lines continue to cause scrubber downtime, but can be controlled by heating the lines or keeping the sodium carbonate solution dilute.

The operability of the FGD system can be calculated from plant logs of the time the FGD system operated divided by the time the boiler operated. For Unit No. 1, the operability averaged 60 percent for July 1975 until April 1976. For unit No. 2 operability averaged 80 percent for the same period.

Since the plant burns a low sulfur coal, SO_2 concentrations entering the scrubber are about 350 parts per million. The effluent contains less than 50 parts per million, and meets the Clark County Nevada Standard of 0.15 pounds per million BTU. The scrubbing efficiency, therefore, is about 85 percent.

16. St. Clair
Detroit Edison
Belle River, Michigan
Coal-Fired: 3.7 Percent Sulfur
Unit No. 6: 160 MW Retrofit,
Limestone Scrubbing
Peabody Engineering
Startup, May 1976

The St. Clair power plant of the Detroit Edison Company is located on the St. Clair River in Belle River, Michigan, approximately 45 miles northeast of downtown Detroit. This plant contains 7 coal-fired steam generating units which have a total net generating capacity of 1775 MW. Unit No. 6 is a coal-fired steam generating unit rated at 325 MW of electrical generation capacity. The boiler was manufactured by Combustion Engineering and placed in service in 1961. The unit operates at excess air rates of 115 to 120 percent.

Two basic types of coal are utilized at this station, a high sulfur coal and a Western low sulfur coal. The high sulfur coal is burned in the unit when the scrubber is in operation.

The emission control system installed on this unit consists of mechanical operations and an electrostatic precipitator (ESP) installed upstream of a wet scrubbing system. The mechanical collectors and ESP are provided for primary particulate control. The wet scrubbing system provides additional particulate removal and primary sulfur dioxide control.

The flue gas desulfurization system consists of two Peabody-Lurgi two-stage wet limestone scrubbing trains with a total flue gas capacity of 50 percent of the flue gas from the No. 6 unit. Flue gas can be bypassed around the scrubbing system. 10 MW of electrical power are consumed by the scrubbing operations.

Each scrubbing train consists of a variable-throat venturi scrubber-absorber module with a plug type throat control. Sulfur dioxide is removed from the flue gas in a two-stage tray tower equipped with a mist eliminator. The cleaned gas is then reheated by mixing with hot air heated from an oil-fired heater. Scrubbing wastes are discharged from the system via pipeline to a 10.8 acre, ten feet deep pond located 1600 feet from the plant. The pond is used exclusively for scrubbing wastes discharge. The pond water is recycled back to the process to the limestone preparation and slurry recycle tanks.

A 30-day vendor qualification run and final acceptance tests were completed by May 29. The final acceptance test consisted of six 4-hour test runs. The SO_2 removal efficiency for high sulfur coal was 90.9 percent. Particulate removal also exceeded design levels.

The utility is now preparing to conduct a 3-month minimum internal scrubber demonstration program to accumulate operating data and information Following the completion of this program the scrubbers will fire low sulfur Decker coal (0.3 to 0.4 percent) to meet SO_2 emission regulations.

17. Scholz

Gulf Power Company
Chattahoochee, Florida
Coal-Fired: 5.0 Percent Sulfur (maximum)
Unit No. 1A: 20 MW Retrofit
Double Alkali
Combustion Equipment Associates/Arthur D. Little
Startup, February 1975

Unit No. 2A: 20 MW Retrofit
Carbon Adsorption
Foster-Wheeler
Startup, February 1976

Unit No. 1B and 2B: 23 MW Retrofit
Dilute Sulfuric Acid
Chiyoda International
Startup, March 1975

Gulf Power Company is conducting an extensive investigation of second generation FGD systems at the Scholz plant. The tests are to

determine performance capabilities and costs under various loads and conditions. Three promising FGD systems were chosen for concurrent testing. Only the Chiyoda system is still being tested. The double alkali tests are complete and the carbon adsorption tests are indefinitely terminated.

Double Alkali

The double alkali system was jointly developed, designed, and installed by Combustion Equipment Associates and Arthur D. Little. It is installed on Boiler No. 1, a Babcock and Wilcox pulverized coal-fired boiler. The system is designed to handle 50 percent of the flue gas from the boiler. The boiler has been retrofitted with a sectionalized, high-efficiency precipitator capable of 99.7 percent particulate removal. The precipitator can be selectively de-energized for study of particulate impact on the FGD operation.

The prototype unit incorporates a high degree of flexibility for generation of design and operating information for a wide variety of applications. Although the basic mode of system operation is double alkali with lime regeneration, the system was designed to operate also with lime or limestone slurries as the scrubbing medium.

The system consists of a venturi scrubber and an absorption tower, with an additional storage silo for limestone, a mix tank, and other assorted tanks, pumps, controllers, and piping.

The system was completed and put in operation by CEA/ADL in early February 1975. In mid-May 1975 an EPA double alkali test program was initiated by Southern Services, CEA, and ADL.

The operation of the system has been summarized by the developers and operators as follows (32):

"Over the course of the year, the process and equipment performance improved significantly with excellent system availability during the final operating period from mid-September 1975 through early January 1976. The process has demonstrated very good reliability, stability of operation, and resistance to upset with no incidents of scrubber or mist eliminator plugging or scaling, even during the last three months of operation with no mist eliminator wash... The system generally operated at SO_2 removal efficiencies of about 95% and demonstrated the capability for removal of over 99%."

Testing of the system has been completed as of July 7, 1976. Test reports will be issued. Overall, the testing program has proven this system's performance at the prototype level, and has indicated its potential use in full scale application.

Foster-Wheeler

The system consists of a 20 MW absorber section and 47.5 MW regeneration and reduction section. The absorber is designed to accept half of the maximum flue gas flow from Unit No. 2. The coal-fired boiler is rated at 40 MW (nominal).

The absorber is a two-stage design consisting of vertical columns of parallel louver beds, which support and contain activated charcoal (char). SO_2 is absorbed by the char pellets from the cross-flowing flue gas at 250 to 300 °F. The char is then regenerated in the regenerator vessel by heating to 1200 °F, driving off the SO_2. The SO_2 rich gas is then passed through a vessel containing crushed coal, resulting in reduction to gaseous elemental sulfur and carbon dioxide. This latter process is carried out at 1300 to 1500 °F.

The initial shakedown on flue gas began August 11, 1975, and proceeded

continuously for 10 days. The regeneration section was operational about 60 percent of the time. SO_2 removal was well above expectations and pressure drop across the adsorber was well below design levels. The system was shut down for correction of several operating problems, equipment modifications, and evaluation of the initial operating data. Operation was resumed in October 1975, when two consecutive runs were conducted with the reduction portion of the system processing front-end off-gas at full operating temperatures. A program of modification was completed on this system in early January 1976. Reintroduction of flue gas into the integrated system commenced on March 15, 1976 and continued through April 4, 1976. The longest run on the unit has been 504 hours with the RESOX section operating only about 25 percent of that period.

Southern Services has discontinued further testing of the unit.

Chiyoda

The system at Scholz can handle one-half the load (53,000 SCFM) from either of the 47 MW boilers. Design absorber inlet SO_2 concentration is 2250 ppm. Various test coals with sulfur contents ranging up to 2.2 percent are burned.

The particulate loads from newly installed electrostatic precipitators on the two units range from 0.02 to 0.1 grains per standard cubic foot. Flue gas from the precipitators is quenched with cooling water to remove additional flyash and to cool the gas before it enters the SO_2 absorber.

SO_2 is absorbed in water and catalytically oxidized with air to form sulfuric acid. The dilute acid is recirculated through the absorber. A bleed stream of the recycling acid is neutralized with limestone to produce gypsum as a by-product.

Many small problems kept the unit from operating well from February

through May 1975. After this initial startup period, the unit has run well, with and average operability of 80 percent from June 1975 through May 1976. The major outages were caused by a breakdown in the centrifuges and failure of some weak joints in the FRP piping. SO_2 removal efficiency has been good, sometimes as high as 95 percent.

The unit was shut down in April 1976 to modify the waste water bleed system. Some of the waste water is to be recycled to the process to reduce the amount of discharge. During the shutdown, a welding accident in the oxidizer caused a fire in which the polypropylene tower internals were damaged. The fire damage has been repaired and the unit has restarted.

18. Shawnee

Tennessee Valley Authority
Paducah, Kentucky
Coal-Fired; 2.9 Percent Sulfur
Unit No. C101-A; 10 MW Retrofit
Lime/Limestone Scrubbing
Chemico
Startup, April 1972

Unit No. C201-B; 10 MW Retrofit
Lime/Limestone Scrubbing
Universal Oil Products
Startup, April 1972

In June 1968, the EPA initiated a program to test prototype lime and limestone systems for removal of sulfur dioxide and particulates from coal-fired boiler flue gases. The program was carried out in a test facility incorporated into the flue gas ductwork of Unit No. 10, a coal-fired boiler at the TVA Shawnee power station, Paducah, Kentucky. TVA is the constructor and facility operator; Bechtel Corporation is the major contractor, test

director, and report writer.

The test facility consists of three parallel scrubber systems of prototype size, treating part of the flue gas from the boiler. Each scrubber train is capable of treating approximately 30,000 ACFM or the equivalent of approximately 10 MW of power plant generating capacity.

Three parallel wet scrubber systems were selected for the test project: 1) a venturi with a spray tower after absorber; 2) a turbulent contact absorber (TCA) and 3) a marble-bed absorber. The venturi system, manufactured by Chemical Construction Co. (Chemico), contains an adjustable throat that permits control and variation of pressure drop under a wide range of flow conditions. The TCA unit, manufactured by Universal Oil Products, incorporates a fluidized bed of low density plastic spheres that are free to move between retaining grids. The marble-bed absorber, supplied by Combustion Engineering Co., uses a packing of 1/4 inch glass marble spheres and a turbulent layer of liquid and gas above the marble layer to enhance mass transfer. Operations with the marble bed unit were hampered by corrosion problems and extensive modifications became necessary. The costs of modification were considered unwarranted because a similar unit operating at Paddy's Run could provide the same process information. Therefore the Shawnee unit (No. C301-C) was shut down in July 1973.

In June 1974, the EPA initiated a 3-year advanced test program at the Shawnee facility with three major goals: 1) continuation of long term testing, emphasizing reliable operation of mist elimination systems at increased gas velocity; 2) investigation of advanced process and equipment design variations for improving system reliability and process economics; and 3) long term reliability testing on promising process and equipment design variations.

The advanced test program has produced significant information on the relationship of demister plugging to alkali utilization. The suit-

ability of diluted clarifier water for demister washing has also been shown. (These results are discussed above in Section II A.)

Tests have also been run to show the effect of FGD systems of variable load. In these tests, hourly adjustments were made to the slip stream feeding the FGD to follow the actual load changes on the boiler. Over the test period, the boiler load varied from 60 to 160 MW and the outlet SO_2 concentration ranged from 1500 to 4500 ppm. The test run lasted about 50 days. The FGD system responded very well to the load changes. There were no operational problems and the system was very clean at the end of the run. The test, which was run on lime, will be repeated with limestone.

Details of the Shawnee test program are available in EPA reports (2,3,4).

19. Sherburne

Northern States Power Co.
Becker Minnesota
Coal-Fired: 0.8 Percent Sulfur
Unit No. 1: 710 MW New Installation
Limestone Scrubbing
Combustion Engineering
Startup, March 1976

The Sherburne County generating plant of the Northern States Power Company is located on the Mississippi River in Sherburne County, near Becker, Minnesota.

This new power generating plant currently has one coal-fired unit operational, one under construction, and two in the early planning stages.

The scrubbing system is comprised of a first stage fixed-rod venturi scrubber for particulate removal and a marble bed absorber to complete particulate removal and achieve SO_2 removal. The scrubbing system has

been guaranteed to remove 99 percent of the particulate matter entering the scrubbing system, or maintain an emission of 0.04 grains per dry standard cubic foot, whichever outlet value is greater; and remove 50% of the sulfur in the fuel (maximum fuel sulfur content of 1.2 percent) or maintain an emission of 200 ppm, whichever outlet value is greater.

The system consists of 12 scrubbing modules, 11 of which are required for full load capacity. An agitated reaction tank is located at the bottom of each scrubber module to provide for completion of SO_2 formation to sulfite, forced oxidation of sulfite to sulfate and precipitation of the calcium sulfate. In forced oxidation, air is bubbled into the reaction tank. The sulfate is precipitated in the reaction tank by addition of gypsum seed crystals.

A bleed line provides the necessary solids removal to a 100 foot diameter clarifier. Here the waste solids (fly ash, calcium carbonate, and calcium sulfate) settle out and the clarified water is returned to the process. The cleaned flue gases pass through a double row, two-pass chevron mist eliminator and are reheated before discharge to the atmosphere. The clarifier underflow is pumped to an 18 inch clay-lined settling pond which is 45 feet deep and 62 acres in area. The water is recycled from the pond back to the process.

The system began full commercial operation May 1, 1976.

20. Valmont

Public Service Company of Colorado
Valmont Colorado
Coal-Fired; 0.72 Percent Sulfur
Unit No. 5; 50 MW Retrofit
Limestone Scrubbing
Universal Oil Products/Public Service of Colorado
Startup, October 1974

The Valmont power station is located approximately 70 miles north of Denver. Valmont No. 5 is a coal-fired unit that fires gas a few months during the year. The coal generally employed for this unit is Wyoming Rosebud, which has an average gross heating value of 10,780 BTU/lb with ash content in the 6 to 7 percent range and sulfur content less than 1 percent.

The FGD system being tested at this station is an experimental unit originally designed by Universal Oil Products for particulate removal only. This TCA unit consists of two parallel modules with a combined capability of treating approximately 100 MW generating capacity (50 MW per module). This system became operational in 1971 and ran until October 1974. Particulate removal efficiency was measured at 95 percent, SO_2 removal efficiency was 45 percent, and availability was approximately 70 percent. Frequent scrubber outages were caused primarily by supersaturated calcium sulfate in the scrubbing liquor. To minimize cleanouts and rectify the scaling problem, a pH control program was implemented for one of the scrubbing modules with addition of limestone to the scrubbing liquor. This modification was expected to minimize scaling, decrease scrubber outages for cleanouts, and increase availability. The expected results did not materialize. Tests during the pH control program showed particulate removal efficiency still at 95 percent. SO_2 removal efficiency increased to 85 percent, and availability remained 70 percent. The unstabilized sludge generated during this operation was pumped to a lined pond.

The FGD unit became inactive in September 1975 when a turbine failure shut the power boiler down. A boiler overhaul was completed in early 1976. Resumption of FGD system operation is planned for late 1976.

21. Will County
Commonwealth Edison
Romeoville, Illinois
Coal-Fired; 3.1 Percent Sulfur
Unit No. 1; 167 MW Retrofit
Limestone Scrubbing
Babcock and Wilcox
Startup, February 1972

The Will County station is described in an EPA report (7).

The FGD system at Will County consists of two parallel modules, designated A and B. Each module has a venturi scrubber for particulate removal, followed by two parallel SO_2 absorption towers. Each absorption tower contains two perforated trays in series, followed by a chevron demister section. Downstream of each module is a bank of steam tube reheaters. An electrostatic precipitator is upstream of the scrubbers. The sludge from the scrubbers is hardened by mixing it with lime and fly ash. Chicago Fly Ash manages the sludge.

The Will County system is one of the first FGD systems installed on a United States power plant. Many operational problems have been encountered since its startup, and extensive work and rebuilding has been undertaken to find solutions. As a result, many problems have been solved; the major remaining problems are discussed below.

Scale deposits on the scrubber internals remain troublesome. The ideal solution would be to prevent scale formation through control of process chemistry. In the meantime scale must be removed by periodically shutting down the scrubber and chipping out the scale.

Plugging has been a persistent problem in the demister section. Water sprays were installed above and below the demisters and these have

helped. Water sprays could probably eliminate the problem, but their use must be limited in order to operate the overall system with a closed water loop.

Tube reheaters have experienced considerable corrosion. The original carbon steel tube bundles have been replaced with a new design.

Operating problems have so far prevented the plant from establishing a strong reliability record for the FGD system. In fact Module B was shut down for a two-year period to concentrate on solving the problems with Module A. There is some evidence that things may be turning around. Between May 1974 and June 1975 the average operability of Module A rose to an encouraging 81 percent. (Module A was then shut down to install the new demisters and restarted in March 1976.)

Performance tests have been run on the scrubbers to determine their efficiency (31). In 22 tests, SO_2 removal efficiency ranged from 66 to 96 percent (84 percent average). Low efficiencies resulted when the limestone was intentionally cut back. The tests were run with SO_2 inlet concentrations ranging from 545 to 2860 parts per million (1570 parts per million average).

APPENDIX B

FUD INSTALLATION LISTS

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TABLE B-1 [illegible]

THE NUCLEAR REPORT DATA

U.S. UTILITY NUCLEAR PLANT NAME	UNIT NAME	LOCATION	START OF CONST.	STATUS	NSSS CLASS
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE [illegible] CONTINUED.

[illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 3-1 continued.

FCC STATIC MODEL DATA

[illegible]	UNIT NAME	LOCATION	START OF DATE	STATUS	NEW CLASS
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

1. [illegible]
2. [illegible]
3. [illegible]

A. [illegible]
B. [illegible]
C. [illegible]
D. [illegible]
E. [illegible]

Table B-2. Cellular-Lord Installations in the United States (Reproduced from Reference 12, Table 1).

Company and Location	Feed Gas Origin	SCFM Treated	Disposition of SO_2
Units on Stream			
Delta Corp./Paulsboro, NJ	Sulfuric Acid Plant	45,000	Recycle to Acid Plant
SOCAL/El Segundo, Cal.	Claus Plant	30,000	Recycle to Claus Plant
Allied Chem./Calumet, Ill.	Sulfuric Acid Plant	30,000	Recycle to Acid Plant
Olin Corp./Curtis Bay, Md.	Sulfuric Acid Plant	78,000	Recycle to Acid Plant
SOCAL/Richmond, Cal.	Claus Plant	34,000	Recycle to Claus Plant
Units in Design or Construction			
SOCAL/Richmond, Cal.	Claus Plant	30,000	Recycle to Claus Plant
SOCAL/El Segundo, Cal.	Claus Plant	30,000	Recycle to Claus Plant
NIPSCO/Gary, Ind.	110 MW Coal Fired Power Plant	310,000	Elemental Sulfur Plant
PSCOM/Freitland, N.M.	670 MW Coal Fired Power Plant	1,880,000	Elemental Sulfur Plant
PSCOM/Freitland, N.M.	1200 MW C-1 Fired Power Plant	2,510,000	Elemental Sulfur Plant
ARCO Polymers/Monaca, Pa.	100 MW Coal Fired Boiler	250,000	

Table B-1. Wellman-Lord Installations in Japan (Reproduced from Reference 12, Table 2).

Company and Location	Feed Gas Origin	SCFM Treated	Disposition of SO_2
Units on Stream			
Japan Syn. Rubber/Chiba	Oil Fired Boiler	124,000	Sulfuric Acid Plant
Lwa Nenryo/Kawasaki	Claus Plant	41,000	Recycle to Claus Plant
Chubu Electric/Nagoya	220 MW Oil Fired Power Plant	390,000	Sulfuric Acid Plant
Japan Syn. Rubber/Yokkaichi	Oil Fired Boiler	290,000	Sulfuric Acid Plant
Sumitomo Chem./Sodegaura	Oil Fired Boiler	225,000	Sulfuric Acid Plant
Kashima Oil/Kashima	Claus Plant	20,000	Recycle to Claus Plant
Mitsubishi Chem./Mizushima	Oil Fired Boiler	373,000	Sulfuric Acid Plant
Tao Nenryo/Hatsushima	Claus Plant	12,000	Recycle to Claus Plant
Toyo Kayon/Nagoya	Oil Fired Boiler	216,000	Sulfuric Acid Plant
Japan Nat. Railroad/Kawasaki	200 MW Oil Fired Power Plant	415,000	Sulfuric Acid Plant
Kotashiki Kayoto/Okayama	Oil Fired Boiler	248,000	Sulfuric Acid Plant
Fuji Film/Fujinomiya	Oil Fired Boiler	99,000	Liquid SO_2
Units in Design or Construction			
Shin Daikyowa/Yokkaichi	Oil Fired Boiler	253,000	
Sumitomo Chem./Niihama	Oil Fired Boiler	91,000	
Mitsubishi Chem./Mizushima	Oil Fired Boiler	390,000	
Mitsubishi Chem./Kurosaki	Oil Fired Boiler	330,000	
Tohoku Electric/Niigata	100 MW Oil Fired Power Plant	236,000	

Table 9-4. Wellman-Lord Installations in West Germany (reproduced from Reference 12, Table 3).

Company and Location	Feed Gas Origin	SIPM Treated	Disposition of SO_2
Units in Design or Construction			
Confidential	357 MW Coal Fired Power Plant	778,000	Liquid SO_2
Confidential	175 MW Coal Fired Power Plant	389,000	Clean Plant

Table B-5. Summary of Significant Operating and Planned Full Scale Double Alkali Systems (Reproduced from Reference 13).

System Operator	System Application	Vendor or Developer	Size (Mt. Equivalent)	Active Alkali	Utilizer Process	Amount of Ash
[illegible]	Reduction Atlas	FMC	12 (Gas Rate) 37 (Regen.)	Conc.	Lime	Dec. 1972
[illegible]	Oil-fired elec. power boiler	Showa Denko	150	Conc.	Limestone	June 1973
[illegible]	Oil-fired utility boiler	[illegible]	150	Conc.	Limestone	Jan. 1974
[illegible]	4 coal-fired industrial boilers	General Motors	40 (Regen) 32 (Gas Rate)	Dilute	Lime	Mar. 1974
[illegible]	2 coal-fired industrial boilers	[illegible] Industries	28-30	Dilute	Lime	Oct. 1974
[illegible]	Oil-fired industrial boiler	Showa Denko	62	Conc.	Limestone	1974
[illegible]	Oil-fired industrial boiler	Showa Denko	95	Conc.	Limestone	1974
[illegible]	Oil-fired industrial boiler	Showa Denko/Ebara	65	Conc.	Limestone	1974
[illegible]	Oil-fired industrial boiler	Showa Denko/Ebara	46	Conc.	Limestone	1974
[illegible]	Oil-fired industrial boiler	[illegible]	67	Conc.	Lime	1974
[illegible]	Oil-fired boiler	[illegible]	65	Conc.	Lime	1974

Table 3-3 (continued)

Tower Owner	Tower Application	Height of Tower	Site No. Constructed	Guide Wires	Lighted	Tower Date
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table B-6. The Chiyoda Thoroughbred 101 Flue Gas Desulfurization Plants (Reproduced from Reference 15, Table 1).

Owner of Plant	Location	Capacity (scfm)	Capacity (MW)	Availability	Period of Availability
Nippon Mining	Minushima	20,800	-	95%	May '73 to Dec. '75
Fuji Kosan	Kainan	58,000	-	97%	May '73 to "
Mitsubishi Rayon	Otake	56,000	30	97%	May '73 to "
Tohoku Oil	Sendai	8,900	-	100%	June '73 to "
Daicel	Abashi	62,000	33	96%	Dec. '73 to "
Amagasaki Cokes	Hyogo	15,500	-	97%	July '74 to "
Hokuriku Electric Power	Toyama	466,000	250	100%	Oct. '74 to "
Mitsubishi Chemical Ind.	Yokkaichi	250,000	135	94%	July '74 to "
Mitsubishi Petrochemical	Yokkaichi	93,900	50	99%	Dec. '74 to "
Mitsubishi Petrochemical	Kawajiri	435,000	235	100%	Dec. '74 to "
Denki Kagaku Kogyo	Chiba	75,000	40	100%	June '75 to "
Hokuriku Electric Power	Fukui	650,000	350	100%	June '75 to "
Toyama Cooperative Power	Toyama	466,000	250	100%	Sept. '75 to "

APPENDIX C

FOD SYSTEM CONFIG

A. Lime and Limestone Systems

Installed and operating costs of lime and limestone systems have been reported in at least three independent studies, as summarized below.

1. The Tennessee Valley Authority (TVA) has made an extensive study of model plants based on various fossil fuel types, percent sulfur, removal efficiency, plant age, and plant size. The original TVA report (14) has recently been updated to reflect current costs (20). The updated TVA estimates of installation and operating costs are summarized in Table C-1.

2. The Department of Commerce (DoC) conducted a study of SO_2 control technology, and developed cost estimates for lime systems (22). The DoC estimates are presented in Table C-2.

3. PEDCo Environmental Specialists have completed a detailed cost estimate of limestone systems (15). The PEDCo estimates are summarized in Table C-3.

Actual costs at a specific plant can vary considerably from the average. The PEDCo study analyzes the following parameters that can affect individual costs: 1) SO_2 removal requirements (affects the amount of raw materials and utilities needed); 2) flue gas flow rate (determines system size); 3) new versus retrofit application (affects design constraints); 4) terrain conditions (affects grading, filling and support requirements); 5) redundancy (spare modules, etc. cost extra); and 6) sludge disposal options. The impact of these parameters was calculated by PEDCo as a percent variation of the model plant costs as shown in Table C-4.

As seen from Table C-4, a combination of factors could increase capital costs for an individual plant two or three times above the model case.

Table C-1. Total Capital Investment Requirements and Total Annual Operating Costs of Lime and Limestone Systems (reproduced in part from Reference 20).

Case	Years Life	Limestone $/kw	Limestone mills/kwh	Lime $/kw	Lime mills/kwh
Coal-fired power unit:					
90% SO_2 removal: reactor solids disposal					
200 MW, new, 3.5% S	30	98.4	6.20	79.9	4.58
200 MW, existing, 3.5% S	20	76.6	4.86	67.6	5.11
500 MW, existing, 3.5% S	25	42.2	3.39	70.0	4.72
500 MW, new, 2.5% S	30	43.5	3.04	55.1	3.33
500 MW, new, 3.5% S	30	48.4	3.41	61.1	3.65
500 MW, new, 5.0% S	30	58.2	3.74	66.3	4.11
1,000 MW, existing, 3.5% S	25	47.5	2.82	51.6	3.40
1,000 MW, new, 3.5% S	30	51.4	2.74	46.9	2.94
90% SO_2 removal: reactor solids disposal					
500 MW, new, 3.5% S	30	35.9	3.23	58.9	3.49
90% SO_2 removal: reactor solids disposal (scrubbing unit without existing particulate collection facilities)					
500 MW, existing, 3.5% S	25	80.6	4.11	70.2	4.28
Oil-fired power unit:					
90% SO_2 removal: reactor solids disposal					
200 MW, new, 2.5% S	30	36.4	3.02	44.5	3.66
500 MW, new, 1.0% S	30	35.6	2.11	43.5	2.55
500 MW, new, 2.5% S	30	42.4	2.44	49.6	3.02
500 MW, new, 4.0% S	30	47.8	2.73	54.3	3.40
500 MW, existing, 2.5% S	25	50.4	2.85	58.7	3.47
1,000 MW, new, 2.5% S	30	32.9	1.90	36.2	2.45

Table C-1 continued: Notes:

Total Capital Investment

Midwest plant location represents project beginning mid-1975, ending mid-1978. Average cost basis for scaling, mid-1977. Minimum in process storage; only pumps are spared. Investment requirements for disposal of flyash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
These investment costs depend heavily on project definition.
Working capital has been included in the total capital investment.
Sludge disposal pond with clay liner.

Total Average Annual Revenue Requirements

Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1978 revenue requirements.
Investment and revenue requirements for disposal of flyash excluded.
Byproduct credit and sludge fixation costs excluded.

Table C-2. Capital and Operating Costs of Lime FGD Systems (reproduced in part from Reference 22 at pages 42 and 43).

Basis	Lime Systems	
	Installation Cost $/kW	Operating Cost mills/kWh
1,000 MW capacity, New plant, Northern Appalachian coal, 3 percent sulfur, in compliance with NSPS.	54-69	3.9-6.2

Table C-1. Capital and Operating Cost of Lime FGD Systems (Reproduced in part from Reference 35, Table II).

Model Plant Characteristics	Limestone Systems: Capital Costs $/kW	Limestone Systems: Annualized Costs mills/kWh
250 Megawatt capacity		
Retrofit, 3.5% S	81	5.18
New, 3.5% S	66	4.17
Retrofit, 0.6% S	74	4.47
New, 0.6% S	59	3.46
500 Megawatt capacity		
Retrofit, 3.5% S	70	4.27
New, 3.5% S	58	3.68
Retrofit, 0.6% S	65	3.63
New, 0.6% S	53	3.05
1000 Megawatt capacity		
Retrofit, 3.5% S	69	4.18
New, 3.5% S	57	3.54
Retrofit, 0.6% S	64	3.59
New, 0.6% S	52	2.87

Note: Plants burning 3.5 percent sulfur coal are assumed to meet the new source performance standard of 1.2 pounds SO_2 per million BTU of heat input.
Plants burning 0.6 percent sulfur coal are assumed to meet 0.15 pounds SO_2 per million BTU.

Table C-4. Typical Capital Cost Variations for Individual FGD Systems (Reproduced in Part from Reference 18, Table III).

Factor	Typical Total Capital Cost Impact, %
SO_2 removal requirements[a]	15-20
Flue gas flow rate[a]	10-30
Installation status[a] (new vs. retrofit)	10-40
Condition of terrain and subsurface[a]	3-15
FGD system redundancy[b]	10-40
Sludge disposal requirements[a] (nonrepresentative processes)	10-30

[a] Variations in capital cost are from a model plant 500 MW/existing/3.5 % S boiler.

[b] Variations in capital cost for 250 - 1000 MW model plants.

The PEEKS study also analyzes the results of a cost survey conducted by the Edison Electric Institute. Utility operators responding to the survey gave actual costs for 19 lime and limestone systems. After adjusting to a common basis, PEEKS found the capital costs ranged from $50 to $88 per kilowatt, with an average of $70 per kilowatt. (Unadjusted costs were $34 to $116 per kilowatt; $78 per kilowatt average.) The adjusted costs for actual systems are therefore in good agreement with estimated costs for model plants. (Refer to Tables C-1, C-2, and C-3.)

Lime and limestone systems produce a throwaway sludge that should be treated before disposal. The treatment cost is in addition to the scrubber costs presented above.

The cost of sludge fixation has been studied by the Aerospace Corporation (36). Cost estimates were obtained from the three principal firms that offer commercial processes: Chemfix, Dravo, and IGCM. Aerospace then adjusted the figures to a common basis, including capital investment, additives, labor, processing, and transportation of sludge 5 miles to the disposal site. The operating costs worked out to 0.9 to 1.4 mills per kilowatt hour ($7.50 - $11.40 per ton of dry waste).

There is little information on actual operating costs because of limited experience with full scale sludge treatment. Two power plants have reported actual costs: Commonwealth Edison's Will County Station, and Duquesne Light's Phillips Station. These figures are included in Table C-5.

In summary, the operating costs for lime or limestone FGD systems are about 3.5 mills per kilowatt hour. Adding the costs of sludge fixation and disposal brings the total to about 5 mills per kilowatt hour.

Table C-5. Sludge Fixation Costs.

Source	Operating Cost mills/kwh	Reference	Remarks
Aerospace estimate	0.9-1.4	(36)	Including flyash disposal; 1976 dollars.
Will County Station	3.98	(7, at Table 3.5)	F. includes hauling cost.
Phillips Station	1.4-1.7	(37)	Converted from 86-97 per cm of wet solids

B. Wellman-Lord Systems

The TVA cost study cited earlier also includes estimates for model plants using a sodium reagent for scrubbing (20). These figures are reproduced in part in Table C-6. Note that credit for sulfur byproducts are not included.

The PEDCo cost study (35) also estimates costs for regenerable sodium scrubbers. The PEDCo numbers are reproduced in part in Table C-7.

Davy Powergas, who holds the patents on the Wellman-Lord process, has estimated average costs for its system (12). The costs vary slightly, depending on the final byproduct; elemental sulfur, sulfuric acid, or liquid SO_2. The estimates are summarized in Table C-8.

The only available figures for actual operation in the United States are projected costs for a 115 MW demonstration unit at the Mitchell station that will produce elemental sulfur. These projections are reported as follows (38):

a) Capital cost, $129/kW;
b) Operating cost, 8.1 mills/kwh.

C. Double Alkali Systems

Cost estimates for double alkali systems have been reported by EPA (13), FMC Corporation (14), and Dunn (39). The results are summarized in Table C-9.

D. Chiyoda Systems

Estimated costs of the Chiyoda system have been reported by Chiyoda International Corporation (15). The costs are shown in Table C-10.

Table C-6. Wellman-Lord Cost Estimates by TVA (Reproduced in Part from Reference 20, Tables 1, and 2).

Case	Years Life	Capital Cost $/kw	Operating Cost mills/kwh
Coal-fired power unit			
70% SO_2 removal; onsite solids disposal			
200 MW, new, 3.5% S	30	112.0	6.60
200 MW, existing, 3.5% S	20	118.0	7.76
500 MW, existing, 3.5% S	25	86.7	6.34
500 MW, new, 2.0% S	30	73.6	4.16
500 MW, new, 3.5% S	30	84.8	5.37
500 MW, new, 5.0% S	30	94.4	6.52
1,000 MW, existing, 3.5% S	25	67.0	5.54
1,000 MW, new, 3.5% S	30	64.2	4.46
80% SO_2 removal; onsite solids disposal			
500 MW, new, 3.5% S	30	80.8	4.98
90% SO_2 removal; onsite solids disposal (existing unit without existing particulate collection facilities)			
500 MW, existing, 3.5% S	25	104.2	7.14
Oil-fired power unit			
90% SO_2 removal; onsite solids disposal			
200 MW, new, 2.5% S	30	71.7	4.62
500 MW, new, 1.0% S	30	42.0	2.55
500 MW, new, 2.5% S	30	57.0	3.74
500 MW, new, 4.0% S	30	61.9	4.87
500 MW, existing, 2.5% S	25	67.2	4.38
1,000 MW, new, 2.5% S	30	40.6	3.17

Table C-6 Continued; Notes:

Total Capital Investment

Midwest plant location represents project beginning mid-1975, ending mid-1978. Average cost basis for scaling, mid-1977. Minimum in process storage; only pumps are spared. Investment requirements for disposal of flyash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
These investment cost depend heavily on project definition.
Working capital has been included in the total capital investment.
Sludge disposal pond with clay liner.

Total Average Annual Revenue Requirements

Power unit on-stream times, 7000 hr/yr. Midwest plant location, 1978 revenue requirements.
Investment and revenue requirements for disposal of flyash excluded.
By-product credit and sludge fixation costs excluded.

Table G-7. Wellman-Lord Cost Estimates by PSXXX
(Reproduced in Part from Reference 35 at Table II).

Model Plant Characteristics	Capital Costs $/kw	Annualized Costs mills/kwh
250 Megawatt Capacity		
Retrofit, 3.5% S	122	6.70
New, 3.5% S	95	5.06
Retrofit, 0.6% S	94	5.33
New, 0.6 % S	70	3.86
500 Megawatt Capacity		
Retrofit, 3.5% S	114	5.83
New 3.5% S	90	4.66
Retrofit, 0.6% S	88	4.59
New 0.6% S	67	3.96
1000 Megawatt Capacity		
Retrofit, 3.5% S	104	5.34
New, 3.5% S	86	4.44
Retrofit, 0.6% S	80	4.10
New, 0.6% S	64	3.41

NOTE: Plants burning 3.5 percent sulfur coal are assumed to meet EPA's new source performance standard of 1.2 lbs. SO_2 per million BTU of heat input.
Plants burning 0.6 percent sulfur coal are assumed to meet 0.15 pounds SO_2 per million BTU.

Table C-8. Wellman-Lord Cost Estimates By Davy Powergas (12).

Base Case	Capital Cost $/kW	Operating Cost mills/kWh
670 MW power plant		
8100 BTU/lb, 1.3 % S Coal		
8000 hr/yr operation		
By-product:		
a) Sulfuric Acid	83	3.4
b) Elemental Sulfur	87	3.7
c) Liquid SO_2	84	2.4

Table C-9. Double Alkali Cost Estimates.

Source	Capital Cost $/kw	Operating Cost mills/kwh	Reference	Remarks
EPA	50-60	2.5-3	(13)	200 MW or larger. 3-4% S Coal. Excluding sludge fixation. New or simple retrofit. 80% load factor. Lime at $30-$33/ton. Soda ash at $65-$70/ton.
FMC		2.039 (excluding Capital Charges)	(14)	300 MW. Midwestern 3.13% S Coal. 90% SO_2 Collection. 50 °F Reheat (half by oil, half by flue gas bypass).
Burn		5	(39)	Converted from reported cost of $10.33 per ton of coal assuming 0.946 pounds coal per net kilowatt-hour produced.

Table G-10. Chiyoda System Cost Estimates.

Source	Capital Cost $/kW	Operating Cost mills/kWh	Reference	Remarks
Chiyoda	76	Not reported.	(15)	500 MW plant. 2% sulfur coal. 90% SO_2 removal. 90% particulate removal. 300 °F gas reheat (oil).

E. Magnesium Oxide Systems

The TVA cost study cited earlier also includes estimates for model plants using magnesium oxide (30). These numbers are reproduced in part in Table C-11. Note that credit for sulfuric acid byproduct is not included.

Few reports have been made of actual costs for operating systems. The information available is summarized in Table C-12. Discounting the high cost of the Eddystone system (which includes the cost of two extra particulate scrubbers) these fragmentary data agree fairly well with the TVA estimates.

Table C-11. Magnesium Oxide System Costs Estimated by TVA (Reproduced in Part from Reference 20, Tables 1 and 2).

Case	Years Life	Capital Cost $/kw	Operating Cost mills/kwh
Coal-fired power unit:			
90% SO_2 removal: recycle disposal			
200 MW, new, 3.5% S	30	95.6	5.03
200 MW, existing, 3.5% S	20	96.1	5.18
500 MW, existing, 3.5% S	25	69.9	4.02
500 MW, new, 2.0% S	30	62.1	3.32
500 MW, new, 3.5% S	30	71.7	4.02
500 MW, new, 5.0% S	30	79.9	4.70
1,000 MW, existing, 3.5% S	25	52.3	3.32
1,000 MW, new, 3.5% S	30	53.0	3.26
80% SO_2 removal: recycle solids disposal			
500 MW, new, 3.5% S	30	69.3	3.83
90% SO_2 removal: recycle solids disposal (working unit without existing particulate collection facilities)			
500 MW, existing, 3.5% S	25	86.3	4.75
Oil-fired power unit:			
90% SO_2 removal: recycle solids disposal			
200 MW, new, 2.5% S	30	60.0	3.30
500 MW, new, 1.0% S	30	34.4	1.96
500 MW, new, 2.5% S	30	43.7	2.58
500 MW, new, 4.0% S	30	51.2	3.13
500 MW, existing, 2.5% S	25	54.6	3.05
1,000 MW, new, 2.5% S	30	32.4	2.20

Table C-11 Continued; Notes:

Total Capital Investment

Midwest plant location represents project beginning mid-1975, ending mid-1978. Average cost basis for scaling, mid-1977. Minimum in process storage; only pumps are spared. Investment requirements for disposal of flyash excluded.
Construction labor shortages with accompanying overtime pay incentive not considered.
These investment costs depend heavily on project definition.
Work capital has been included in the total capital investment.

Total Average Annual Revenue Requirements

Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1978 revenue requirements.
Investment and revenue requirements for disposal of flyash excluded.
Byproduct credit and sludge fixation costs excluded.

Table C-12. Magnesium Oxide System Costs.

Plant	Capital Cost $/kw	Operating Cost mills/kwh	References	Remarks
Eddystone	193		(19, at viii)	Not representative, since the FGD unit is 105 MW and the cost includes 300 MW of first stage particulate scrubbers.
Dickerson		5.1	(40)	Actual operating cost for the Dickerson station (estimated); excludes by-product credit and regeneration costs.

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Note: Papers presented at EPA Flue Gas Desulfurization Symposiums are reprinted in the following EPA reports:

a) "Proceedings: Symposium on Flue Gas Desulfurization - Atlanta, November 1974", Volumes I, II; EPA-650/2-74-126a,b (Dec. 1974).

b) "Proceedings: Symposium on Flue Gas Desulfurization, New Orleans, March 1976", Volumes I, II; EPA-600/276-136a,b (May 1976).

The reports are available through the National Technical Information Service, Springfield Virginia 22161.